VISION 21 SYSTEMS ANALYSIS METHODOLOGIES

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ABSTRACT

Under the sponsorship of the U.S. Department of Energy/National Energy Technology Laboratory, a multi-disciplinary team led by the Advanced Power and Energy Program of the University of California at Irvine is defining the system engineering issues associated with the integration of key components and subsystems into power plant systems that meet performance and emission goals of the Vision 21 program. The study efforts have narrowed down the myriad of fuel processing, power generation, and emission control technologies to selected scenarios that identify those combinations having the potential to achieve the Vision 21 program goals of high efficiency and minimized environmental impact while using fossil fuels. The technology levels considered are based on projected technical and manufacturing advances being made in industry and on advances identified in current and future government supported research. Included in these advanced systems are solid oxide fuel cells and advanced cycle gas turbines. The results of this investigation will serve as a guide for the U. S. Department of Energy in identifying the research areas and technologies that warrant further support.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Under the sponsorship of the U.S. Department of Energy/National Energy Technology Laboratory, a multi-disciplinary team led by the Advanced Power and Energy Program of the University of California at Irvine is defining the system engineering issues associated with the integration of key components and subsystems into power plant systems that meet performance and emission goals of the Vision 21 program. . The study efforts have narrowed down the myriad of fuel processing, power generation, and emission control technologies to selected scenarios that identify those combinations having the potential to achieve the Vision 21 program goals of high efficiency and minimized environmental impact while using fossil fuels. The technology levels considered are based on projected technical and manufacturing advances being made in industry and on advances identified in current and future government supported research. Included in these advanced systems are solid oxide fuel cells and advanced cycle gas turbines. The results of this investigation will serve as a guide for the U. S. Department of Energy in identifying the research areas and technologies that warrant further support.

The overall objectives of the Vision 21 program are:
- produce electricity and transportation fuels at competitive costs
- minimize environmental impacts associated with fossil fuel usage, and
- attain high efficiency

The efficiency targets are 75% (LHV) for natural gas fueled plants and 60% (HHV) for coal fueled plants producing electricity only, that is, plants without CO_2 capture nor co-production of any transportation fuels or H_2.

Specifically, the objective of this program being conducted by APEP (University of California at Irvine) led team is to identify gas and coal based system configurations that meet the above Vision 21 goals with emphasis on attaining the highest performance. The results of this investigation will serve as a guide for the U. S. Department of Energy in identifying the research areas and technologies that warrant further support.

The approach taken consists of first identifying the sub-systems that make up a complete power plant followed by a screening analysis in order to narrow down the number of possible configurations for more detailed analysis. Without fuel cells, gas turbine based cycles alone cannot meet the efficiency goals of the Vision 21 program. These include inter-cooled, reheat, and recuperated cycles (e.g., Ericsson), combined cycles including those incorporating bottoming cycles such as the Kalina cycle, and the Humid Air Turbine (HAT) cycle (Rao, A.D., 1989). This is true even though the HAT cycle can have a higher combustor exhaust temperature since the cycle is not as much constrained by NOx emissions as most other gas turbine-based cycles (Bhargava, A., 1999). Thus, gas turbines integrated with fuel cells (hybrids) are required for these Vision 21 power plants.

The following summarizes the major findings of the cycle analysis conducted for the natural gas based plants during this reporting period:

HIGH PRESSURE SOFC INTEGRATED WITH HIGH PRESSURE RATIO INTERCOOLED GAS TURBINE

It was determined that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric. If higher air to fuel ratio were used in the HP SOFC, then in order to meet the efficiency goal, an alternate approach consisting of installing a second SOFC between the HP and LP turbines would be required (a “reheat cycle”). This alternative configuration, however, did not significantly improve performance and would increase plant cost and complexity.

The optimum efficiency of the cycle occurred at an OPR greater than 50, while the gas turbine firing temperature was modest, <1200 C. As mentioned above, several configurations resulted in nearly equal performance, e.g., a non-intercooled gas turbine with an OPR of 20 had an efficiency only 0.3 points lower, well within computational error. When efficiency was a toss up, the intercooled gas turbine was chosen because of its higher power density (kW/air flow), a factor that would mitigate the system costs. This is especially true with the hybrid since the optimum cycle efficiency occurs when the only heat to the gas turbine is from the SOFC – the hot exhaust further heated by catalytic combustion of the remaining hydrocarbons in the exhaust. Since these temperatures seldom exceeded 1150 - 1200 C, power (kW/air flow) is somewhat limited.

HIGH PRESSURE SOFC INTEGRATED WITH HAT

It was determined also for this configuration that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric while if higher air to fuel ratios are to be utilized in the SOFC, then in order to meet the efficiency goal, the alternate approach consisting of installing a second SOFC between the HP and LP turbines is required. This alternate cycle configuration as pointed out earlier would increase the plant cost and complexity and was discarded from further consideration.

The optimum efficiency of the cycle occurred at an OPR of approximately 20, which is much lower than the previous case, while the gas turbine firing temperature remained at a modest value of <1200 C.

ATMOSPHERIC PRESSURE MCFC INTEGRATED WITH INTERCOOLED GAS TURBINE

It was found that in order to reach the 75% (LHV) efficiency target for this hybrid case, the fuel utilization had to be increased from the 85% value that was employed in the two SOFC hybrid cases to 90% fuel utilization resulting in a correspondingly lower heating value for the depleted fuel for the MCFC hybrid. The optimum OPR for the gas turbine from an efficiency standpoint for the proposed selected case was 25 while the gas turbine inlet temperature remained at a modest value of <1100C.

HIGH PRESSURE SOFC INTEGRATED WITH O_2 BREATHING HAT CYCLE

It was determined for this configuration that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric while if higher air to fuel ratios are to be utilized in the SOFC, then in order to meet the efficiency goal, the alternate approach consisting of installing a second SOFC between the HP and LP turbines is required. This alternate cycle configuration as pointed out earlier would increase the plant cost and complexity and was discarded from further consideration.

ADVANCED RANKINE CYCLE COMBUSTING H_2 WITH O_2

The efficiency of the cycle is estimated at 52% on a LHV basis.

EXPERIMENTAL

No experimental work was conducted as part of this program.

RESULTS AND DISCUSSION

KICK-OFF MEETING

A kick-off meeting was held at the Advanced Power and Energy Program of the University of California, Irvine (UCI) between the study participants consisting of University of California, Kraft Work Systems, and Spencer and Associates on September 14 and 15, 2000. The scope was discussed to establish the strategy for execution of this study.

PROJECT COORDINATION MEETING

A project coordination meeting was held at the Advanced Energy and Power Program of UCI between the study participants consisting of UCI, kraft Work Systems, and Spencer and Associates on October 26 and 27, 2000. The meeting also served as an alignment meeting between the study participants resulting in further definition and refinement of the work plan. The resulting detailed work plan and scope definition for this study are presented in the next section.

FIRST STATUS REVIEW MEETING

A presentation was made to the NETL in March 2001 in Pittsburgh, PA. The work plan as well as the results developed were presented at this Project Review meeting. The need for data from the developers of the technologies such as advanced air separation, advanced membrane reformer and advanced gasification that would be incorporated in the Vision 21 power plant concepts being defined by this study was emphasized. The following describes the "Work Plan."

WORK PLAN

<u>TASK 1 - EVALUATION OF POTENTIAL VISION 21 POWER PLANTS</u>

Analyses to identify the combination of fuel, fuel processing, power generation, and emission control technologies that potentially meet VISION 21 goals for performance and emissions.

Task 1.1 - Market and Economic Data

In order to the assist in the identification of the plant configurations that meet these above goals, the following data will be developed:

1. Pricing and availability projections for
a) Natural gas
b) Coal
c) Petroleum coke (maybe negative cost or a credit may be taken)
d) Heavy oil (maybe negative cost or a credit may be taken)
e) Biomass (maybe negative cost or a credit may be taken)

2. Pricing and market projections for
a) Dimethyl ether (potential substitute for diesel, LNG)
b) Fischer-Tropsche liquids (possible premium blending feedstock, since the sulfur and nitrogen contents are zero)

3. Pollution abatement credit for
a) CO2

4. Economic Analysis
a) Cost of electricity methodology for a deregulated industry (levelized COE may not have meaning)
b) Trade-off between capital cost and operating cost in order to provide information on how much efficiency is worth (in the form of a plot of efficiency versus capital cost for a given cost of electricity)

Task 1.2 - Identification of Modules and Subsystems

Construct Unified Database

To ensure wide variety of possible fuels, fuel processing, power generation and emissions control devices and equipment are fully defined, a unified database will be constructed describing key chemical, physical, and operating characteristics for the foregoing categories. Nearly all of these parameters have been identified in prior or on-going programs. Values used in this database will be based on latest published information as well as on extrapolations by industry experts. The database will also contain, at a minimum, first-order cost estimates ($/$10^6$ Btu, $/kW, $/lb., etc.) for key components and subsystems.

An abridged representation of items to be put into the database is shown in Fig. 1. For each of the items, key characteristics will be listed; e.g., chemical properties and physical parameters defining input and output streams, chemical/physical constraints on input streams, current and projected limitations on operating parameters, etc. Knowledge of these characteristics will allow linking of combinations of fuel, fuel processing power generation, etc. For example, in Fig. 1, the characteristics of gas (pipeline) allow it to be used (combusted) without major treatment in gas turbines, steam boilers, combined cycles, HAT cycles and fuel cells (reformation). Coal can be directly used in various fluid beds, in steam boilers and in indirectly fired cycles. It must be processed (e.g., gasified) before it can be used in gas turbines, etc. The effluents from the power generation systems may require further emission controls. Gas turbine and combined cycles may need further NOx removal; HAT cycles should not. Systems combusting coal will need FGD, NOx, particulate, and trace element removal devices. Some systems may benefit from CO_2 removal, but it is hoped that the high efficiencies of the VISION 21 systems will meet CO_2 requirements. By knowing the characteristics at each of the linking points, the issues associated with integrating the various components and subsystems can be identified.

Initial sorting on this database will allow early elimination of some combinations of fuels, processes, and power systems. As a simple example, consider the characteristics of the fuel specifications for high performance gas turbines, e.g., levels of sulfur, alkaline metals, vanadium, etc. in the low ppm range. Fuels matching these requirements are limited to natural gas and distillate oils. Coal, heavy petroleum fractions, and biomass must be processed and cleaned before they can be "integrated" with the power generation system. The processing must produce a fuel with high enough calorific value to reach combustion temperatures above 2700 F, usually meaning that the fuel conversion process (gasification) must use oxygen rather than air. Alternately, air blown gasification coupled with hot gas cleanup providing fuel gas to the gas turbine at approximately 1000F may be required. This rather simple sorting has eliminated from consideration the direct combustion of several fuels, indicated that fuel processing will probably be oxygen based, and set the requirements for gas clean up. Sorting on the characteristics of fuel cleanup systems would identify candidates for use with high performance gas turbines. While some of these factors could have been identified a priori, the unified database assures that characteristics of the components and subsystems are considered on a reasonable and consistent basis.

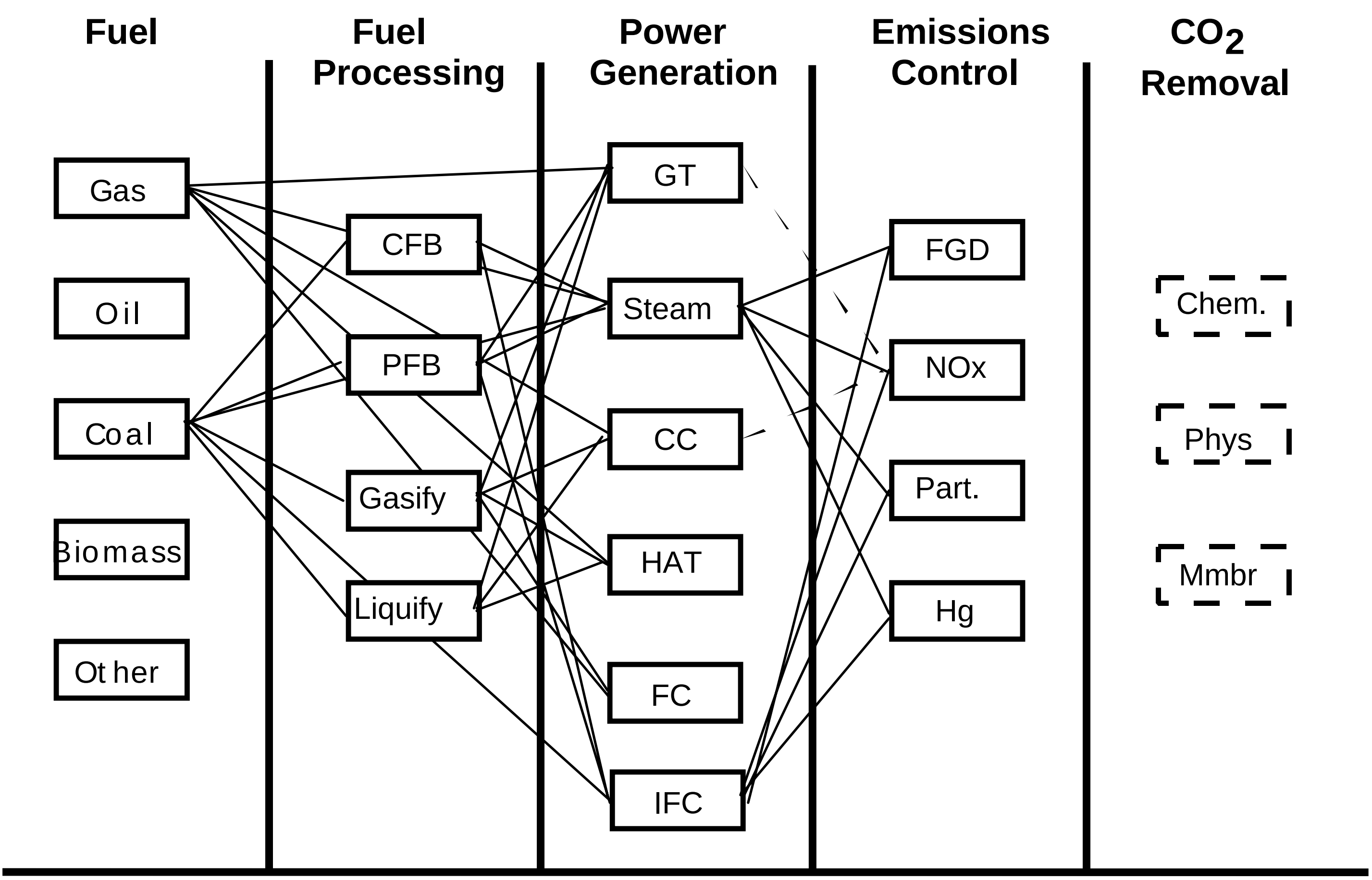

Fig. 1: Representative Database and Potential Links

CC – Combined Cycle
CFB – Circulating Fluid Bed
FC – Fuel Cell
FGD – Flue Gas Desulfurization
HAT – Humid Air Turbine
IFC- Indirectly Fired Cycle
Mmbr - Membrane
PFB – Pressurized Fluid Bed

Those combinations that are expected to closely approach or meet the VISION 21 goals of 60% efficiency (HHV) for solid/liquid based systems and 75% efficiency (LHV) for gas based systems would be selected for further detailed analyses to identify the technical parameters that affect component/subsystem integration.

Deliverables

1) Narrative description of the data base construction and of the narrowing down process to the selected (20) cases (paper and electronic file copies).
2) Overall Block Flow Diagrams showing fuel processing, power generation and emissions control technologies for the selected cases.

Task 1.3 – Preliminary Performance Evaluation

Design Basis

In conjunction with DoE, design basis and design point operating conditions such as those shown in Table 1 will be established:

Table 1: Design Basis

Design Parameter	Value
Plant Location	U.S. Mid West
Water Quality/Availability	Fresh water/as required
Base Gaseous Fuel	Natural gas available by pipeline at plant site at pressure as required by a given cycle
Base Solid Fuel	Pittsburgh No. 8 coal, washed and sized, available at plant site by rail
Alternate Fuels	Petroleum coke, heavy oil, biomass
Ambient Dry Bulb Temperature	15 C
Ambient Relative Humidity	60%
Elevation	sea level
Plant Size	Natural Gas: Same as corresponding Base Case (single GE 7H gas turbine based combined cycle and IGCC: Same as corresponding Base Case (single GE 7H gas turbine based IGCC
Power Plant Load Factor	90%

Gas Turbine Exhaust Heat Recovery Unit Pressure Drop	.033 bar
Gas Turbine Exhaust Heat Loss	0.5%
Maximum SOFC Operating Pressure	As required
Steam Generator Pinch Temperature	9 ^{o}C minimum
Boiler Feed Water Sub-cooling to Evaporator	9 ^{o}C minimum
Steam Drum or Humidifier Blowdown	0.5% of evaporation rate
Shift Reaction Approach to Equilibrium	15 ^{o}C
Reforming Reaction Approach to Equilibrium	25 ^{o}C
Pressure Drop in Heat Exchangers	2% minimum
Temperature Approach in Heat Exchangers	10 ^{o}C minimum
CO2 Removal	85% Carbon Recovery (Temperature/Pressure to be Specified)
Export Heat	Steam or Hot Water (Temperature/Pressure to be Specified)

Identification of Promising Plant Configurations

A variety of power plant configurations will be identified in more detail, that is, the configuration of the sub-systems chosen in Task 1.2 will be identified for:

- fuel processing
- power generation
- and emissions control technologies.

Selection of the type of the air separation unit and its integration with the power block, type of gasifier, the type of sulfur removal process will be made in this task. Next, the number of plant configurations will be narrowed down based on initial high level thermodynamic analysis to only those combinations of technologies whose performances are expected to exceed 90% of the DoE goals for VISION 21 power plants. The configurations (minimum of 10 such configurations) will be further evaluated through the use of sophisticated computer simulations in Task 1.4.

Deliverables

1) Description of the selection sub-system technologies and the rationale for selection.

2) Results of the high level thermodynamic analysis and selection/recommendation of the processes for more detailed analysis.
3) Process descriptions of these selected cases.
4) Block Flow Diagrams for the selected cases supplemented with Process Flow/Cycle Diagrams as necessary.

Task 1.4 – Detailed Performance Evaluation

Base Case Plant Configurations

A Base Case for a coal fueled plant and a Base Case for a natural gas fueled plant will be recommended based on technology expected to reach maturity within next 5 to 10 years (utilizing GE H technology based gas turbine combined cycles). Computer simulation models will be constructed for detailed analysis.

Promising Technologies for Detailed Evaluation

Those combinations of technologies identified in Task 1.3 as having the potential of reaching the VISION 21 performance goals will be further evaluated. Conceptual plant designs will be identified and computer simulation models constructed for detailed analysis. Parametric analyses will be carried out to define the range of operating conditions necessary for each configuration to reach the DoE VISION 21 performance goals. Conceptual designs that require conditions well beyond currently projected capabilities for the 2010 –2020 time frame will be reviewed and judgement made as to the realism of attaining the required conditions. Flow sheets identifying the system components and the system heat and mass balance will be prepared for those configurations that meet or exceed the DoE VISION 21 performance goals.

Deliverables

1) Process descriptions of the Base and the selected cases.
2) Block Flow Diagrams and subsystem Process Flow/Cycle Diagrams for the above cases.
3) Parametric analysis including exergy analysis of the operating conditions for the selected cases.
4) Discussion of results and recommendations.

TASK 2 – IDENTIFICATION OF ISSUES RELATING TO SYSTEM INTEGRATION

For those conceptual designs having the greatest performance potential as identified in Task 1, interface conditions between major components and subsystems will be reviewed and any issues that would affect the linking of the components and subsystems into a viable VISION 21 power plant will be identified.

Task 2.1 - Review Interface Conditions

The conceptual designs having the greatest performance potential will be selected for review of the interface conditions between major components and subsystems. Battery limits will be defined for major components and subsystems and the flow of material and energy between these will be identified in terms of physical and thermodynamic characteristics at design point operation.

Task 2.2 – Identify Potential Design Point Integration Issues

Operating parameters identified in Task 1 for the components and subsystems will be compared to the operating parameters of the selected conceptual designs. Conditions outside of the parameter limits will be noted and potential problems associated with linking the components and subsystems will be identified. As an example of a major interface issue, current and near future operation of solid oxide fuel cells in hybrid power systems are limited to pressures under 10 bar. ATS-type gas turbines operate at 20+ bar and advanced aeroderivative gas turbines that could evolve from the Flexible Gas Turbine Systems program could operate at 40+ bar. Linking of these technologies will require significant advances in seals, high temperature piping, etc. In addition, other interface issues could arise; e.g., many of the advanced materials identified for high temperature piping and heat exchangers are not yet code approved for these uses, a process taking several years.

Task 2.3 – Effects of Power Plant Operation on Integration

Off-design Performance

The effects of off-design operating requirements (start up and shut down, part load operation, sensitivity to ambient conditions and response to transient and emergency conditions) on component and subsystem integration will be identified. Overall plant performance during part load operation, sensitivity to ambient conditions (ambient temperature, humidity and barometric pressure) will be quantified while response to transient and emergency conditions will be qualitatively discussed.

CO2 Mitigation

The suitability of the selected cases to CO2 mitigation will be quantified at the design point condition, that is heat and material balances will be developed for each of these cases and the overall plant performance projections quantified. The CO2 will leave the plant boundary limits at the conditions as specified in the Design Basis and the ultimate disposal of the CO2 will not be part of the scope of this study.

Export of Heat

The suitability of the selected cases to export of heat in the form of steam or hot water (temperature and pressure to be established in the Design Basis) will be quantified at the design point condition, that is heat and material balances will be developed for each of these cases and the overall plant performance projections quantified.

Coproduction of Chemicals

The suitability of the selected cases to coproduction of chemicals (either dimethyl ether or Fischer Tropsche liquids) will be quantified at the design point condition (for the gasification based cases), that is heat and material balances will be developed and the overall plant performance projections quantified. An advantage of such coproduction plants is that amount of the corpoduct produced may be adjusted such that the net amount of power exported to the grid may be varied as the demand for (or price of) power changes. The performance of these coproduction plants as "off-design" cases will be developed for 2 additional operating points with different amounts of net power/coproduct production rates. The coproduct synthesis unit will be sized for the maximum coproduct synthesis rate.

Deliverables

1) Report summarizing findings of above tasks (Task 2.1, 2.2 and 2.3).
2) Process descriptions (Task 2.3).
3) Block Flow Diagrams and subsystem Process Flow/Cycle Diagrams (Task 2.3).
4) Plant performance summaries (Task 2.3).
5) Discussion of results (Task 2.1, 2.2 and 2.3).

TASK 3 – IDENTIFY NON-TECHNICAL ISSUES AFFECTING INTEGRATION

Operation of power plants in the new era of electric and gas utility deregulation could be significantly different than historic operational patterns. It is projected, for example, that the 21st century power plant will rely heavily on operational flexibility, quick dispatching capability, and the ability to use opportunity fuels to meet the demand for least cost power expected from merchant power producers. These requirements could affect the arrangement of power plant components and subsystems, the overall flows of material and energy, and, thus, the manner in which system integration is carried out.

Task 3.1 – Sensitivity to Co-feeding Other Feedstocks

The suitability of the selected coal based (gasification) cases to other feedstocks (petroleum coke, heavy oil and biomass) will be quantified at the design point condition, that is heat and material balances will be developed and the overall plant performance projections quantified for gasification based plants producing power from coal and a single other feedstock (repeated for each of the other identified feedstocks). The other feedstock will be gasified in a separate gasifier if the selected coal gasifier is found to be inappropriate (that is, the other feedstock and coal will not be blended in such cases).

Task 3.2 – Rough Order of Magnitude Cost

ROM capital and operating cost estimates will be prepared to assist in the analysis to the conducted in Task 3.5 for all cases developed in Tasks 2.1, 2.3 and 3.1.

Task 3.3 - Identify Operability Criteria

Conduct reviews of operation of deregulated utilities and independent power producers and interview representative power producing organizations to identify key criteria affecting how a power plant operates in a competitive environment. Power plant operators will be interviewed to establish operating preferences. Policy problems such as siting power plants will be addressed.

Task 3.4 – Determine Effect on Integration

The preferred operational characteristics identified in Task 3.3 will be applied to the VISION 21 plants selected for Task 2.1 and potential effects on plant design and configuration that would result in changes affecting component and subsystem integration will be identified. Any changes in performance between the optimum VISION 21 plants of Task 2 and the reconfigured VISION 21 plant will be noted.

Task 3.5 – Define Operational Figure(s) of Merit

The performance differences identified in Task 3.4 could result in additional fuel costs and increase output of Greenhouse gases. The design/configuration changes, however, should result in a more robust system operation and generate higher revenues. A figure(s) of merit will be defined that accounts for changes in performance and costs between the optimum VISION 21 power plant and the VISION 21 plant that viably meets operational requirements in the deregulated market.

Deliverables

1) Process descriptions (Task 3.1).
2) Block Flow Diagrams and subsystem Process Flow/Cycle Diagrams (Task 3.1).
3) Plant performance summaries (Task 3.1).
4) Results of the above analysis (Task 3.1 through 3.5) presented as part of the final report.

TASK 4 – RECOMMENDATIONS FOR FURTHER RESEARCH AND DEVELOPMENT

The interface issues identified in Tasks 2 and 3 will be reviewed to identify the major technical areas that would benefit from further R&D.

Task 4.1 – Identify Status of Integration Issues

Many of the integration issues identified in Tasks 2 and 3 may already be subjects of ongoing or planned R&D. The status of these efforts will be identified and, where appropriate, recommendations made for changes in emphasis or timing.

Task 4.2 – Recommendations for Further R&D

Integration issues not already being considered will be identified and recommendations made for R&D programs to resolve these issues.

Deliverable

1) Results of the above analysis/findings inn Task 4.1 and 4.2 presented as part of the final report.

TASK 5 – PREPARE FINAL REPORT

Deliverable

1) Paper and electronic file copies of Final Report.

MISCELLANEOUS ACTIVITIES

1. At the request of NETL/DoE, during the August-September, 2000 time frame, developed graphics for inclusion into the Vision 21 brochure that was being prepared by Dr. Larry Ruth. Information Supply
2. At the request of NETL/DoE, information concerning the gas turbine and steam turbine being proposed by Foster Wheeler as part of their HIPPS/Vision 21 was developed. Specifically, steam cooling of the gas turbine and cycle conditions for the steam turbine were considered.

CYCLE ANALYSIS - TASK 1: EVALUATION OF POTENTIAL VISION 21 POWER PLANTS

SOAPP MODULE UPDATE

The initial effort on Task 1 of the study consisted of review and bringing up to date the modules for the SOAPP simulation for coal gasification, gas cleanup, expanders etc. Because of the advanced gas turbine technology anticipated for the Vision 21 applications, the turbine cooling estimating process was also reviewed.

DESIGN CRITERIA

An initial list of assumptions concerning operating characteristics of equipment such as boilers, heat exchangers, humidifiers was compiled as part of the design basis to be used in this study.

TABLE 2: PRELIMINARY LISTING OF DESIGN CRITERIA - PROPOSED FOR VARIOUS BALANCE OF PLANT EQUIPMENT

CYCLES WITH HEAT RECOVERY STEAM SYSTEMS

Configuration
< 70 Mw, Use Non–Reheat Steam Cycle; > 70 MW, Typically Use Reheat

Heat Loss	
GT Exhaust Side	1%

Steam Side (Superheated Steam – Temperature Drop)	7 F
Steam Side (Reheated Steam – Temperature Drop)	5 F
Pressure Drop	
GT Exhaust Side (Non–Reheat Steam Turbine)	12 in. H_2O
GT Exhaust Side (Reheat Steam Turbine)	16 in. H_2O
SCR (Selective Catalytic Reduction Device) – Non–Steam Injection Cycles	2 in. H_2O
High Pressure Superheated Steam (Pipe Losses)	6.3%
Intermediate Pressure Superheated Steam (Pipe Losses)	3.3%
Reheated Steam (Pipe Losses)	3.3%
Steam To Reheater (Pipe Losses)	3.3%
High Pressure Evaporator (Pipe Losses)	1.8%
Intermediate Pressure Evaporator (Pipe Losses)	1.8%
High Pressure Superheater Coil	3.8%
Reheater Coil	5.0%
Intermediate Pressure Superheater Coil	3.1%
Low Pressure Superheater Coil	20 psi
Superheated Steam Temperatures (For Gas Turbine Exhaust Temperature >= 975 F)	
High Pressure Steam (See Below For Pin.ch Restrictions)	900 To 1100 F
Reheated Steam (See below For Pin.ch Restrictions)	900 To 1100 F
Intermediate Pressure Steam	500 F
Low Pressure Steam	345 F
Pinch Temperatures	
High Pressure Superheated Steam	Minimum 75 F
Reheated Steam	Minimum 75 F
High Pressure Evaporator	15 F
Intermediate Pressure Evaporator	15 F
Low Pressure Evaporator	20 F
Approach Temperatures	
Boiler Feedwater Temperature Approach To Steam Drum Temperature:	
High Pressure Boiler Feedwater	15 F
Intermediate Pressure Boiler Feedwater	15 F
Low Pressure Boiler Feedwater/Integral Deaerator	20 F
Boiler Feedwater Pressure (At Pump Discharge)	
Hp Boiler Feedwater to Steam Drum Pressure Ratio	1.415
IP Boiler Feedwater to Steam Drum Pressure Ratio	1.304
Low Pressure Boiler Feedwater to Deaerator	+20 psi

Evaporators	
Blowdown (Percentage Of Steam Produced)	1.0%
Transition Duct From GT to Heat Recovery Unit	
Heat Loss (Temperature Drop)	2 F
Steam Turbine Pressures (For Gas Turbine Exhaust Temperature >= 975 F):	
High Pressure Throttle	1465 psia
High Pressure Exit	377 psia
Intermediate Pressure Exit	68 psia
Surface Condenser	
Hot Side Pinch Temperature	10 F
Subcooling	4 F
Deaerator	
Operating Pressure	90 psia
Vent	500 lb/hr
Fuel Gas Heater	
Hot Side Pinch	20 F
Effectiveness	90%
Intercooler	
Cold Side Pinch	20 F
Effectiveness	90%
Blowdown Flash Drum	
Operating Pressure	95 psia

HUMID AIR TURBINE CYCLE

Intercooler	
Cold Side Pinch	20 F
Effectiveness	90%
Pressure Drop (Water Side)	5 psi
Pressure Drop (Gas Side – Exchanger & Piping)	3.0%
Aftercooler	
Cold Side Pinch	20 F
Effectiveness	90%
Pressure Drop (Water Side)	5 psi
Pressure Drop (Gas Side & Piping)	1.0%

Pumps (Pressure At Pump Discharge over Saturator Pressure)

Saturator Bottoms Circulation	+100 psi
Demineralized Makeup Water	+40 psi
Dehumidifier	
Gas Side Pressure Drop	4 in. H_2O
Water Recovery	80%
Heat Recovery Unit	
<u>Heat Loss</u>	
GT Exhaust Side	1.0%
Preheated Humid Air (Temperature Drop)	5 F
<u>Pressure Drop</u>	
GT Exhaust Side	12 in. H_2O
Recuperator (Humid Air & Piping)	2.5%
Economizer (Water Side)	20 Psi
<u>Pinch Temperatures</u>	
Economizer (Cold Side)	25 F
<u>Effectiveness</u>	
Humid Air Recuperator	90%
Economizer	90%
<u>Heat Loss (Temperature Drop)</u>	
Transition Duct From GT to Heat Recovery Unit	2 F
Saturator	
Blowdown (Percentage Of Evaporated Water)	1.0%
Diameter	14 ft
Height Of Packing	40 ft
Pinch Temp. Between Entering Gas and Exiting Water (At Bottom Of Column)	20 F
Pressure Drop (Saturator & Piping)	1.0%
Heat Exchangers	
<u>Fuel Gas Heater</u>	
Hot Side Pinch	20 F
Effectiveness	90%
Pressure Drop (Both Sides)	5 Psi
<u>Intercoolers</u>	
Hot Side Pinch	20 F
Effectiveness	90%

Pressure Drop (Water Side)	5 psi
Pressure Drop (Gas Side)	See Below

STEAM INJECTED CYCLE

Heat Recovery Steam Generator

Heat Loss	
GT Exhaust Side	1.0%
Steam Side (HP Superheated Steam – Temperature Drop)	7 F
Steam Side (IP Superheated Steam – Temperature Drop)	5 F
Pressure Drop	
GT Exhaust Side	12 in. H_2O
CR	2 in. H_2O
HP Evaporator (Pipe Losses)	1.8%
IP Evaporator (Pipe Losses)	1.8%
HP Superheater Coil	3.8%
IP Superheater Coil	3.1%
Effectiveness	
HP Superheater	90%
IP Superheater	90%
Pinch Temperatures	
HP Evaporator	15 F
IP Evaporator	15 F
LP Evaporator	20 F
Boiler Feedwater Temperature Approach To Steam Drum Temperature	
HP Boiler Feedwater	15 F
IP Boiler Feedwater	15 F
LP Boiler Feedwater/Integral Deaerator	20 F
Boiler Feedwater Pressure At Pump Discharge	
HP Boiler Feedwater to Steam Drum Pressure Ratio	1.415
IP Boiler Feedwater to Steam Drum Pressure Ratio	1.304
LP Boiler Feedwater to Deaerator	+20 psi
HP Superheated Steam Pressure over Combustor Pressure	75 psi
IP Superheated Steam Pres. Over Turbine Injection Point Pres.	TBD
Evaporators	
Blowdown (Percentage Of Steam Produced)	1.0%

<u>Heat Loss (Temperature Drop)</u>	
Transition Duct From GT to Heat Recovery Unit	2 F
Deaerator	
Operating Pressure	17 psia
Vent	500 lb/hr
Heat Exchangers	
<u>Fuel Gas Heater</u>	
Hot Side Pin.ch	20 F
Effectiveness	90%
<u>Intercooler</u>	
Cold Side Pinch	20 F
Effectiveness	90%
Blowdown Flash Drum	
Operating Pressure	20 psia

CHEMICALLY RECUPERATED CYCLE

Heat Recovery Steam Generator	
<u>Heat Loss</u>	
GT Exhaust Side	1.0%
<u>Pressure Drop</u>	
GT Exhaust Side	12 in. H_2O
HP Evaporator (Pipe Losses)	1.8%
Intermediate Pressure Evaporator (Pipe Losses)	1.8%
<u>Pinch Temperatures</u>	
HP Evaporator	15 F
IP Evaporator	15 F
LP Evaporator	20 F
<u>Boiler Feedwater Temperature Approach To Steam Drum Temperature</u>	
HP Boiler Feedwater	15 F
IP Boiler Feedwater	15 F
LP Boiler Feedwater/Integral Deaerator	20 F
<u>Boiler Feedwater Pressure At Pump Discharge</u>	
HP Boiler Feedwater to Steam Drum Pressure Ratio	1.415
IP Boiler Feedwater to Steam Drum Pressure Ratio	1.304

LP Boiler Feedwater to Deaerator	+20 psi
Evaporators	
Blowdown (Percentage Of Steam Produced)	1.0%
Transition Duct From GT to Heat Recovery Unit	
Heat Loss (Temperature Drop)	2 F
Reformers	
Approaches To Equilibrium	
Shift	0 F
Reforming	50 F
Heat Transfer Effectiveness	90%
Heat Loss	
HP Reformate (Temperature Drop)	7 F
IP Reformate (Temperature Drop)	5 F
Pressure Drop	
HP Reformate Over Combustor Pressure (Pipe Losses)	75 psi
IP Reformate Over Combustor Pressure (Pipe Losses)	TBD
HP Reformer Coil	4.5%
IP Reformer Coil	3.7%
Deaerator	
Operating Pressure	17 psia
Vent	500 lb/hr
Heat Exchangers	
Fuel Gas Heater	
Hot Side Pinch	20 F
Effectiveness	90%
Intercooler	
Cold Side Pinch	20 F
Effectiveness	90%
Blowdown Flash Drum	
Operating Pressure	20 psia

TASK 1.2: IDENTIFICATION OF MODULES AND SUBSYSTEMS

Options for the sub-systems for the various fuels were depicted in Figure 1 along with various combinations for linking of the fuel with the fuel processing technology, power generation technology and emissions control technology. The characteristics of pipeline quality natural gas allow it to be used directly in gas turbine based cycles such as an intercooled gas turbine, a combined cycle, a Humid Air Turbine (HAT) cycle [Rao, 1989], or combusted in steam boilers, typically without any fuel processing. Natural gas may also be used in fuel cells after some treatment (desulfurization, humidification and reforming). Among the various power generation options for natural gas as shown in Figure 1, direct combustion in a steam boiler may be eliminated, the thermal efficiency of the other options consisting of utilizing gas turbines or fuel cells being significantly higher. Next, with respect to emissions control technology, the intercooled gas turbine and combined cycles may need further NOx control, while the HAT cycle should not require any form of NOx control. This is because the large concentration of water vapor in the combustion air minimizes the formation of thermal NOx (Bhargava, 1999). The fuel cells, which oxidize the fuel electrochemically, will not require any form of NOx control either.

These same options consisting of gas turbine based technologies or fuel cells can be used in coal based plants if the coal is gasified to produce syn gas and the contaminants removed from the syn gas prior to supplying the gas to the power block, fuel specifications for fuel cells and high performance gas turbines being very stringent (high performance gas turbines have stringent limits on levels of contaminants that include sulfur, alkaline metals, vanadium). Alternately, if coal is directly used as in various types of fluid beds or in pulverized steam boilers or in indirectly fired cycles, the effluent from the power generation systems will require extensive post combustion emission controls such as flue gas desulfurization, NOx, particulate and trace element removal devices. In gasification on the other hand, the syn gas cleanup to remove contaminants such as the sulfur and nitrogen compounds, and particulates is performed on a gas stream with a significantly smaller volume and with contaminant concentrations significantly higher, making it much easier to remove. Heavy petroleum fractions and biomass must also be processed and cleaned in a similar manner before these fuels can be “integrated” with the power generation system.

The gasification sub-system is further divided into number of processing units including the oxidant supply unit. Whether the gasification process uses oxygen or air depends on the operating temperature of the gasifier and whether hot syn gas clean up is utilized. With air blown systems, the efficiency of the gasifier (by itself) is lower and larger down stream equipment is required for processing the syn gas which is diluted with nitrogen. For a gasifier operating at high temperatures (in excess of 1000C), the nitrogen accompanying the oxygen in the air increases the degradation of the chemically bound energy of the coal into sensible heat energy within the gasifier which is carried away with the syn gas, thus reducing the cold gas efficiency of the gasifier. On the other hand, the air separation unit is eliminated along with its parasitic loads and high capital cost.

This initial Sub-system Selection task has eliminated from consideration the direct combustion of the fuels, indicated that fuel processing in case of coal will be either oxygen or air blown gasification depending on the gasifier operating temperature and syn gas cooling, and set the requirements for gas clean up based on the specifications dictated by the high performance gas turbines and fuel cells. Note that the gasification option makes the power cycles fuel flexible.

TASK 1.3: PRELIMINARY PERFORMANCE EVALUATION

Power Generation Technology

The first analysis was of a state of the art air-cooled gas turbine. The reason for air cooling is that many of the scenarios to be considered do not have steam raising as a part of the system and the addition of such a system just for cooling would compromise performance. A simple cycle configuration with two spools was selected. This allowed realistic assessment of pressure ratios from 10 to 50 without worrying about compressor surge that could result when a fixed speed, single shaft machine is considered. Turbine temperatures (combustor exit temperatures, T_4) from 2000 F to 3000 F were considered. The lower temperature is approximately that which could be expected from the combustion of the exhaust products of a SOFC and the upper temperature is an estimate of the level that would be anticipated in commercial engines in the 2015 time frame. A nominal 250 MW output at 2732 F (1500 C) and 25 OPR was chosen as a design point for the analysis. A value of 93% polytropic was selected as the compressor efficiency and a 93% adiabatic efficiency was selected for the turbine. These represent stretch from current state of the art machines. Cooling air was varied as a function of T_4 and OPR and the value was set by assuming that a constant blade life would be attained at all temperature levels. The performance results are shown in Figures 2 and 3.

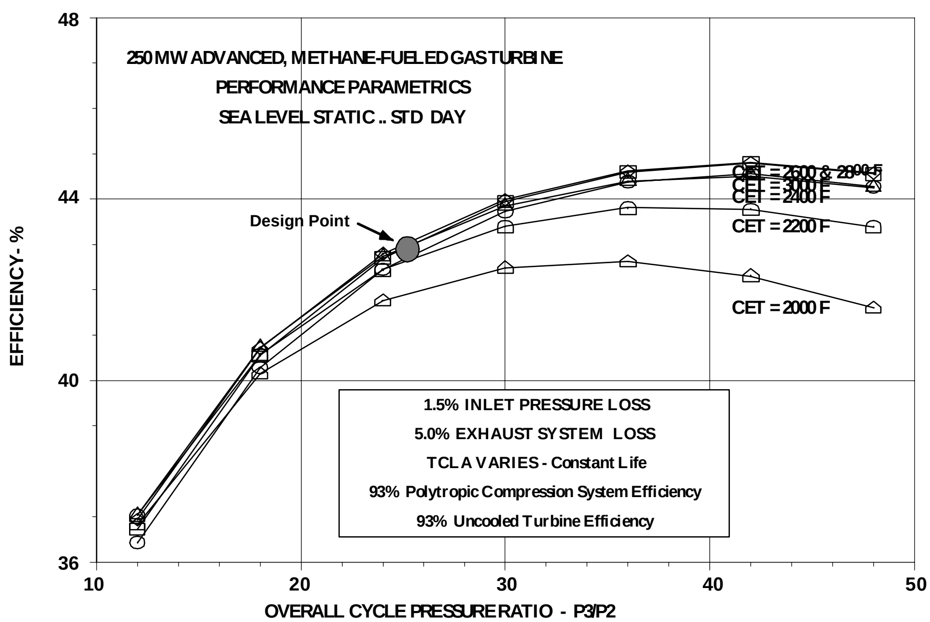

FIG. 2: EFFICIENCY OF SIMPLE CYCLE GAS TURBINE

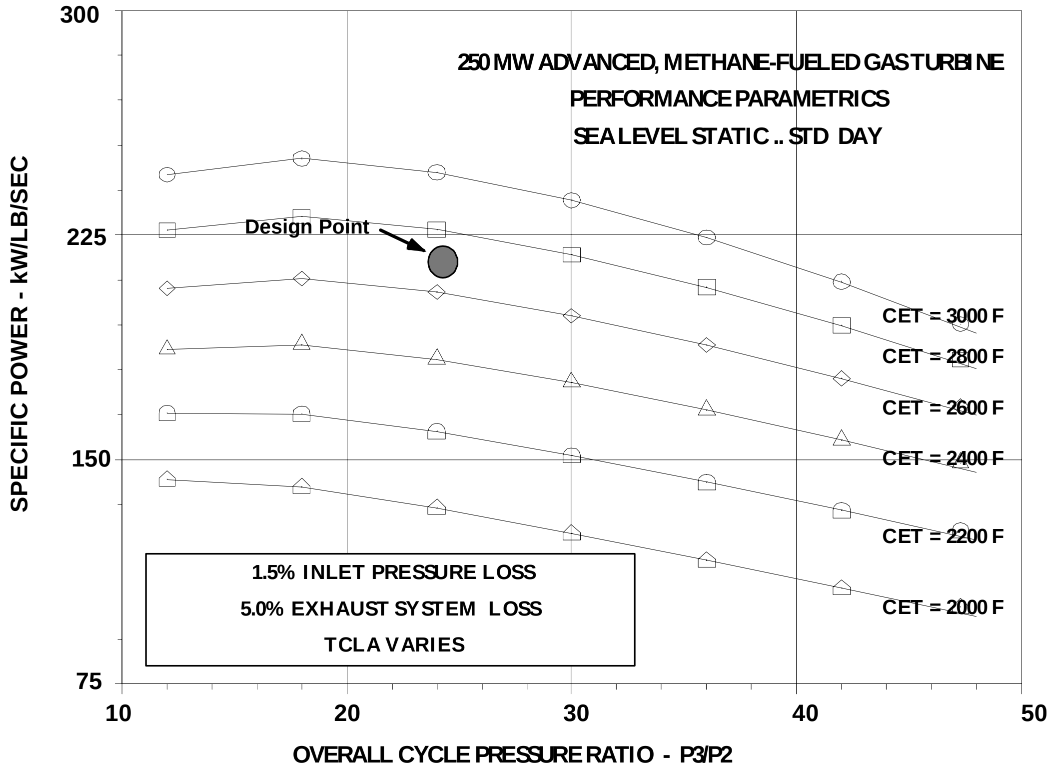

Fig. 3: Specific Power of Simple Cycle Gas Turbines

The deign point selected, which is attainable by either a single shaft or dual spool machine, does not result in either the highest efficiency or the highest power density. It was selected simply as a starting point to develop the trends for gas turbine selection and to identify the internal relations in the gas turbine (a series of cooling curves and other internal information is not included in this report).

It is obvious that a simple cycle gas turbine cannot attain the Vision 21 goals. The maximum efficiency from Fig. 2 is approximately 45% at an OPR of approximately 45. At this pressure ratio, intercooling becomes an option. For example, the PW candidate for DOE's Next Generation Turbine program is an intercooled two spool machine having an OPR of approximately 60 and a T_4 similar to that in the previous analysis. Its efficiency is near 50%, better, but not capable of meeting the goals alone.

At this point, a series of parametric studies were carried out at to ascertain 1) if higher temperatures and very advanced turbines, e.g., uncooled, could attain the DOE goals and 2) the performance trends at extreme conditions up to stoichiometric combustion. The results are shown in Table 3.

TABLE 3: GAS TURBINE CYCLES USING NATURAL GAS

Intercooled Cycles					Intercooled/Recuperative Cycles				
OPR	TIT, F	PWR, MW	EFFIC, %	Pwr/Lb	OPR	TIT, F	PWR, MW	EFFIC, %	Pwr/Lb
10	2750	183.7	35.04	0.286	10	2750	171.3	58.12	0.266
	3000	205.6	34.68	0.320		3000	190.6	59.05	0.296
	3200	222.1	34.14	0.345		3200	204.5	59.40	0.318
	3400	251.8	35.47	0.391		3400	226.1	60.55	0.351
	3600	265.1	34.36	0.412		3600	242.3	60.87	0.377
	3700	274.2	34.13	0.426		3700	249.8	60.94	0.388
	3798	282.9	33.88	0.440		6676	461.3	55.25	0.717
20	2750	213.7	42.15	0.332	20	2750	202.8	58.46	0.315
	3000	241.7	41.98	0.376		3000	227.9	59.89	0.354
	3200	263.2	41.59	0.409		3200	246.9	60.67	0.384
	3400	291.5	42.12	0.453		3400	272.6	61.96	0.424
	3600	315.7	41.90	0.491		3600	293.7	62.58	0.457
	3700	327.4	41.71	0.509		3700	303.8	62.79	0.472
	3855	345.3	41.35	0.537		5739	527.2	63.14	0.820
40	2750	231.7	47.44	0.360	40	2750	223.3	57.14	0.347
	3000	264.9	47.60	0.412		3000	253.8	59.14	0.395
	3200	291.0	47.43	0.452		3200	277.3	60.33	0.431
	3400	322.9	48.02	0.502		3400	306.8	61.84	0.477
	3600	351.6	47.94	0.547		3600	332.5	62.78	0.517
	3700	365.8	47.82	0.569		3700	345.0	63.14	0.536
	3917	396.1	47.44	0.616		5213	549.0	65.75	0.853
50	2750	235.0	48.78	0.365	50	2750	227.6	56.45	0.354
	3000	269.8	49.05	0.419		3000	259.8	58.63	0.404
	3200	297.2	48.98	0.462		3200	284.7	59.95	0.443
	3400	330.2	49.61	0.513		3400	315.3	61.56	0.490
	3600	360.3	49.58	0.560		3600	342.5	62.60	0.532
	3700	375.1	49.49	0.583		3700	355.7	63.01	0.553
	3938	410.2	49.12	0.638		5075	552.4	66.16	0.859
60	2750	236.9	49.72	0.368	60	2750	230.4	55.79	0.358
	3000	272.9	50.12	0.424		3000	263.9	58.13	0.410
	3200	301.3	50.12	0.468		3200	289.9	59.56	0.451
	3400	335.2	50.79	0.521		3400	321.4	61.25	0.500
	3600	366.3	50.82	0.569		3600	354.0	62.71	0.550
	3700	381.7	50.75	0.593		3700	363.5	62.83	0.565
	3956	420.9	50.41	0.654		4973	553.9	66.34	0.861
70	2750	237.5	50.34	0.369	70	2750	232.2	55.17	0.361
	3000	274.3	50.84	0.426		3000	266.7	57.64	0.415
	3200	303.6	50.91	0.472		3200	293.6	59.17	0.456

	3400	338.1	51.62	0.526		3400	325.9	60.92	0.507
	3600	373.9	52.23	0.581		3600	359.1	62.44	0.558
	3700	385.9	51.66	0.600		3700	369.4	62.62	0.574
	3972	428.6	51.34	0.666		4894	554.4	66.39	0.862
80	2750	230.5	49.29	0.358	80	2750	226.2	53.71	0.352
	3000	267.3	49.93	0.416		3000	260.8	56.32	0.405
	3200	296.5	50.09	0.461		3200	287.8	57.95	0.447
	3400	331.0	50.88	0.515		3400	320.1	59.79	0.498
	3600	366.6	51.54	0.570		3600	349.0	61.04	0.543
	3700	378.8	51.01	0.589		3700	363.7	61.60	0.565
	3985	423.6	50.74	0.658		4890	548.5	65.69	0.853

These systems approach 65% efficiency as temperatures approach stoichiometric levels. The intercooled and recuperated configurations has the highest efficiencies and the highest power densities. These configurations are used as the basis for the gas turbine cycles in Task 1.4.

Next, performance for various types of gas turbine cycles was developed. The results are presented in Figure 4 in showing the thermal efficiency of the cycle on a LHV basis as a function of the combustor exhaust temperature. As can been from these results, cycles based on a gas turbine alone without fuel cells cannot meet the efficiency goals of the Vision 21 program. The efficiency of an advanced combined cycle utilizing a steam cooled gas turbine, even with a combustor exhaust temperature as high as 1900C, is in the mid-to-high 60% (65-68% LHV) range ,which is significantly lower than the 75% (LHV) goal for natural gas. With the HAT cycle, a higher combustor exhaust temperature may be utilized since the cycle is not as much constrained by NOx emissions as the combined cycle (Chen, et al., 2002). Still, the efficiency is limited to less than 70% (LHV) for natural gas. <u>Thus, gas turbines integrated with fuel cells (hybrids) are required for these Vision 21 power plants.</u>

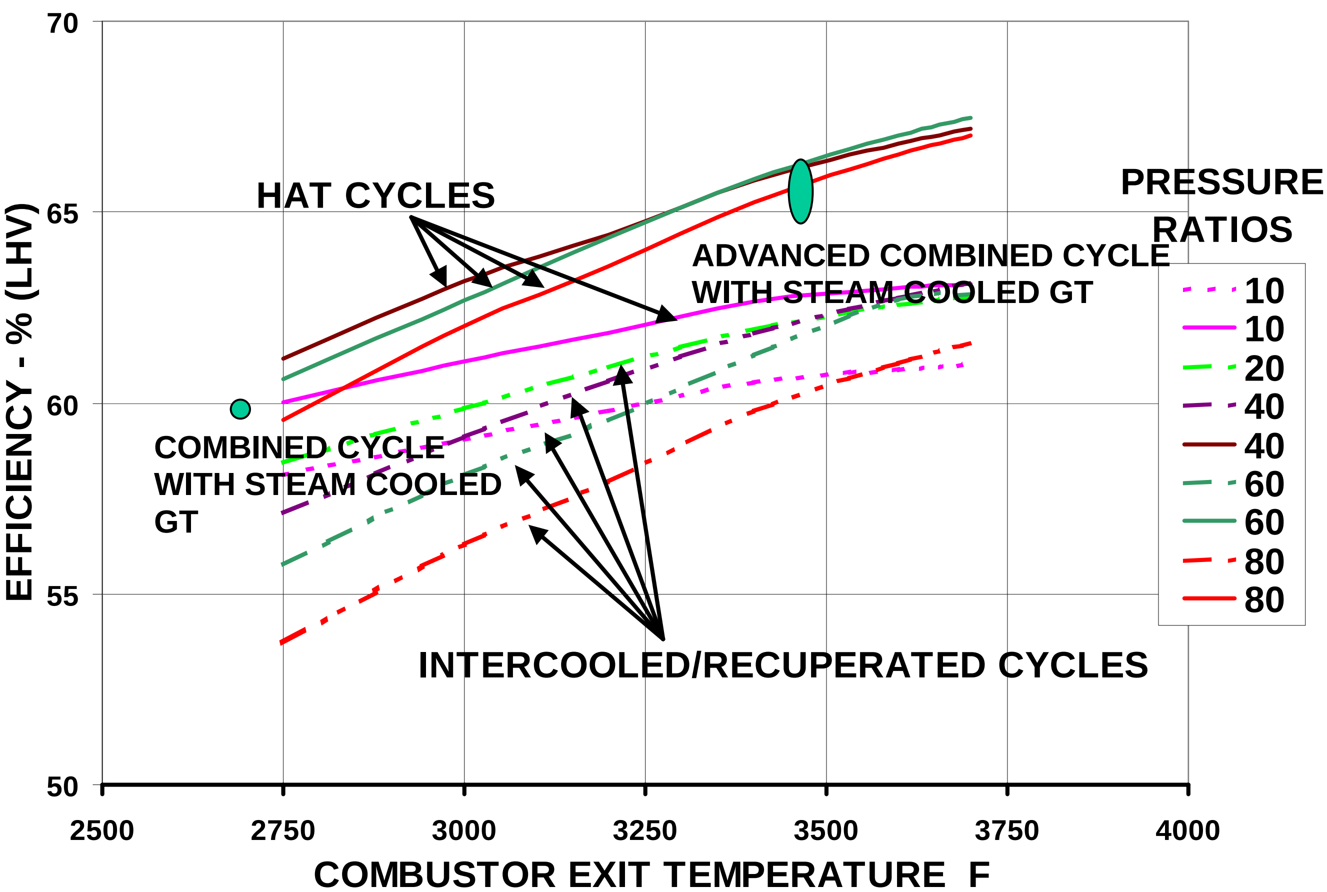

FIGURE 4: THERMAL EFFICIENCY OF VARIOUS GAS TURBINE BASED CYCLES

Overall System Selection

Three hybrid cycles are identified for the natural gas based plants that have the potential to reach the Vision 21 efficiency goal:

1. High pressure solid oxide fuel cell (SOFC) integrated with a high-pressure ratio intercooled gas turbine
2. High pressure solid oxide fuel cell (SOFC) integrated with the HAT cycle
3. Atmospheric pressure molten carbonate fuel cell (MCFC) integrated with a high-pressure ratio intercooled gas turbine.

Two "zero emission" natural gas based plants, that is, plants recovering the carbon dioxide for carbon sequestration are also identified for the screening analysis:

1. High pressure SOFC integrated with O_2 breathing HAT cycle and CO_2 recycle
2. Advanced Rankine cycle (using gas turbine technology) combusting H_2 with O_2 in rocket engine technology combustor.

Three cases are identified for the coal-based plants that have the potential to reach the Vision 21 efficiency goal:

1. Shell gasifier with hot gas cleanup providing syn gas to a high pressure SOFC based hybrid
2. Texaco gasifier providing syn gas to a high pressure SOFC integrated with the HAT cycle
3. Foster-Wheeler partial gasifier integrated with a SOFC based hybrid.

Two "zero emission" coal based plants are identified for the screening analysis:

1. Shell gasifier with hot gas cleanup providing syn gas to a high pressure SOFC integrated with O_2 breathing HAT cycle and CO_2 recycle
2. Shell gasifier with hot gas cleanup and H_2 separation using high temperature membranes (precombustion CO_2 recovery) and the advanced Rankine cycle (using gas turbine technology and H_2/air combustor derived from the rocket engine technology).

An additional case that coproduces Fischer-Tropsch liquids (in addition to electric power) is also identified for the screening analysis:

1. Texaco gasifier with cold gas cleanup providing syn gas to a Fischer-Tropsch synthesis unit with unconverted gas supplied to an advanced HAT system.

This case represents an advanced coal-based power system in which a high value liquid fuel is produced along with electric power. Because the main product is the liquid fuel, the power system may not operate as a base load plant and may, in fact, operate with several stops and starts per day. This means that the plant is not tightly integrated and that fuel (syn gas) is delivered "across the fence" to the power system. Because of the probable need for on/off and extensive part-load operation, a lower cost, less complex, but still highly efficient power system such as a HAT would be the choice. The part load performance of the HAT cycle has been compared to that of a combined cycle; the heat rate of an integrated gasification HAT (IGHAT) remains essentially constant down to 50% load whereas in the case of an integrated gasification combined cycle (IGCC), the heat rate increases by as much as 30% on a single train basis [Rao et.al., 1993].

The approach used/to be used in developing these various cases starts out with a basic design (using relatively near term technology) for system components of each of the cases where applicable. If Vision 21 targets were not realized, then advanced designs would be incorporated for each of the subsystems till the Vision 21 efficiency goals are reached. These advanced concept subsystems are listed below (in the suggested order of evaluation) when applicable to a given case. The resulting efficiency of the overall plant with the various technologies evaluated for each case will also be documented.

1. Gas Turbine - cooling air technology, materials, firing temperature, inclusion of reheat, component efficiencies
2. Steam Turbine – materials, temperature, pressure, efficiency
3. Air Separation Unit (ASU) - replace conventional ASU with Advanced Cryogenic ASU or Ionic Transport Membrane (ITM)
4. Gasifier - repalce Texaco or shell with Wlisonville transport gasifier or GE EERC gasification process or hydro gasifier.

Task 1.4: Detailed Performance Evaluation – Natural Gas Cases

The nominal power output for the plant has been selected as 300 MW to be representative of the minimum economic size for central power stations, especially those with gasification. Each of the systems has a gas turbine component. The design values for the turbines used in the screening analyses are summarized in Table 4. Note that the initial screening analyses considered a variety of gas turbine and fuel cell configurations and operating conditions. The complex interaction of air/steam/fuel streams often resulted in several configurations for each case that had similar performance, i.e., efficiencies within +/- 2%, well within the "noise" of the analyses. The results presented below for some of the cases are for the configurations with the highest efficiency for each case and may not represent the best configuration when all operating constraints are considered. That is the goal of the future tasks of this study – analysis of selected configurations to identify operability and economic considerations.

TABLE 4: GAS TURBINE DESIGN BASIS

Ambient Conditions	ISO
Firing Temperature	≤ 1700 C
Compressor Isentropic Efficiency	≥ 90%
Turbine Isentropic Efficiency	≥ 93%
Turbine Materials	Ceramics and Thermal barrier Coatings

<u>High Pressure SOFC Integrated with High Pressure Ratio Intercooled Gas Turbine</u>

The system as depicted in Figure 5 consists of an intercooled gas turbine integrated with a pressurized tubular SOFC. Atmospheric air is compressed in an intercooled compressor, comprised of a low pressure (LP) compressor and a high pressure (HP) compressor. The discharge air from the HP compressor is supplied to the

SOFC as its oxidant. The fuel utilization in the SOFC was set at 85%. Desulfurized fuel is humidified in a column where it is counter-currently contacted with hot water. A portion of the water is evaporated into the fuel stream, the heat required for the humidification operation being the heat recovered from the intercooler and the stack gas by circulating water leaving the humidifier. The humidifier fuel is then preheated in the turbine exhaust and supplied to the SOFC. The exhaust from the SOFC, consisting of the depleted air and the depleted fuel is supplied to the combustor of the gas turbine. The exhaust from the combustor enters the HP turbine which drives the HP compressor and is expanded to a pressure which is higher than atmospheric. The exhaust from the HP expander is supplied to the LP turbine where it is expanded to near atmospheric pressure and then supplied to the heat recovery unit. The LP turbine drives the LP compressor and the generator.

It was determined that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric. If higher air to fuel ratio were used in the HP SOFC, then in order to meet the efficiency goal, an alternate approach consisting of installing a second SOFC between the HP and LP turbines would be required (a “reheat cycle”). This alternative configuration, however, did not significantly improve performance and would increase plant cost and complexity.

The optimum efficiency of the cycle occurred at an OPR greater than 50, while the gas turbine firing temperature was modest, <1200 C. As mentioned above, several configurations resulted in nearly equal performance, e.g., a non-intercooled gas turbine with an OPR of 20 had an efficiency only 0.3 points lower, well within computational error. When efficiency was a toss up, the intercooled gas turbine was chosen because of its higher power density (kW/air flow), a factor that would mitigate the system costs. This is especially true with the hybrid since the optimum cycle efficiency occurs when the only heat to the gas turbine is from the SOFC – the hot exhaust further heated by catalytic combustion of the remaining hydrocarbons in the exhaust. Since these temperatures seldom exceeded 1150 - 1200 C, power (kW/air flow) is somewhat limited.

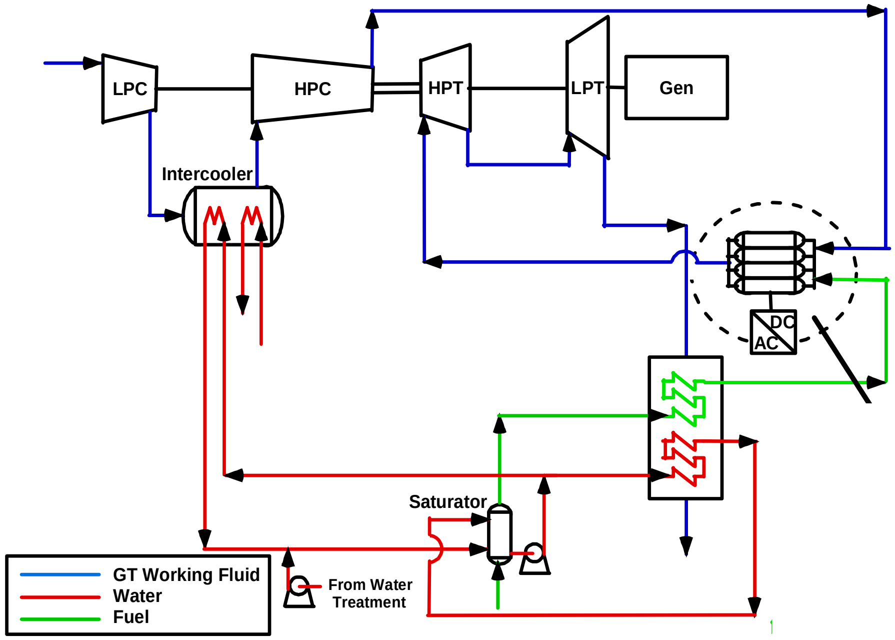

FIGURE 5: HIGH PRESSURE SOFC/INTERCOOLED GAS TURBINE HYBRID

High Pressure SOFC Integrated with HAT

The system as depicted in Figure 6 is similar to the previous case consisting of an intercooled gas turbine integrated with a pressurized tubular SOFC except that it incorporates humidification of the air and the humidified air is preheated in a recuperator in the turbine exhaust before it is fed to the SOFC. The fuel utilization in the SOFC was again limited to 85%. The air leaving the compressor is first cooled in an aftercooler and then introduced into the humidifier column where it comes into counter-current contact with hot water. A portion of the water is evaporated into the air stream, the heat required for the humidification operation being recovered from the intercooler and the stack gas by circulating water leaving the humidifier. The desulfurized fuel is also humidified in a similar manner.

It was determined also for this configuration that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric while if higher air to fuel ratios are to be utilized in the SOFC, then in order to meet the efficiency goal, the alternate approach consisting of installing a second SOFC between the HP and LP turbines is required. This alternate cycle configuration as pointed out earlier would increase the plant cost and complexity and was discarded from further consideration.

The optimum efficiency of the cycle occurred at an OPR of approximately 20, which is much lower than the previous case, while the gas turbine firing temperature remained at a modest value of <1200 C.

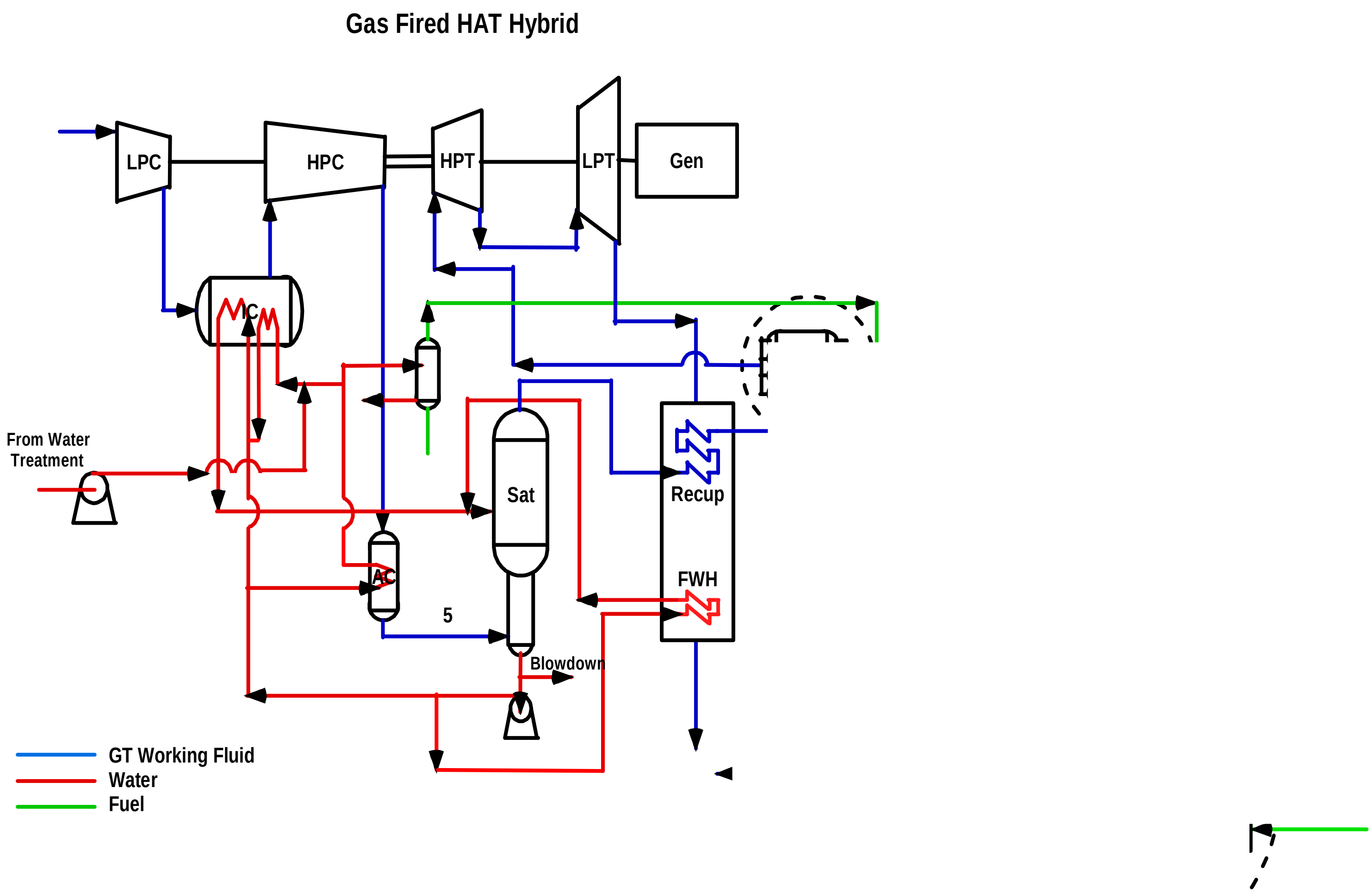

FIGURE 6: HIGH PRESSURE SOFC/HAT HYBRID

Atmospheric Pressure MCFC Integrated with Intercooled Gas Turbine

A number of configurations of the atmospheric MCFC were considered including several in which the exhaust of the MCF was cooled, compressed to gas turbine operating conditions, recuperated and further heated by combusting the remaining hydrocarbons. The configuration with the best performance, however, is that shown in Figure 7. This system consists of an intercooled gas turbine integrated with an atmospheric pressure MCFC. Atmospheric air is compressed in an intercooled compressor, comprised of a LP compressor and a HP compressor. The discharge air from the HP compressor is preheated in a high temperature heat exchanger transferring the heat released from combustion of the depleted fuel leaving the MCFC. This hybrid case may require a catalytic combustor because the depleted fuel is at lower temperature (typically in the neighborhood of 600C in the case of MCFC versus 1000C in the case of SOFC) and also lower pressure when compared to the SOFC based hybrids. Furthermore, it was found that in order to reach the 75% (LHV) efficiency target for this hybrid case, the fuel utilization had to be increased from the 85% value that was employed in the two SOFC hybrid cases to 90% fuel utilization resulting in a correspondingly lower heating value for the depleted fuel for the MCFC hybrid.

A blower provides the required amount of air for the combustion of the depleted fuel; the combustion air being first preheated in the heat recovery unit located downstream of the combustor. This configuration was found to be more efficient than a configuration where the combustion air is also supplied by the gas turbine exhaust; utilizing a separate combustion air blower increases the amount of heat that may be recovered form the exhaust gas in the heat recovery unit. In addition to providing heat for preheating the gas turbine working fluid and preheating the depleted fuel combustion air, the exhaust gas in the heat recovery unit provides heat for preheating the humidified fuel gas supplied to the MCFC and for preheating the circulating water for the desulfurized natural gas humidifier. A portion of the heat rejected by the intercooler is also recovered for the humidifier.

The optimum OPR for the gas turbine from an efficiency standpoint for the proposed selected case was 25 while the gas turbine inlet temperature remained at a modest value of <1100C.

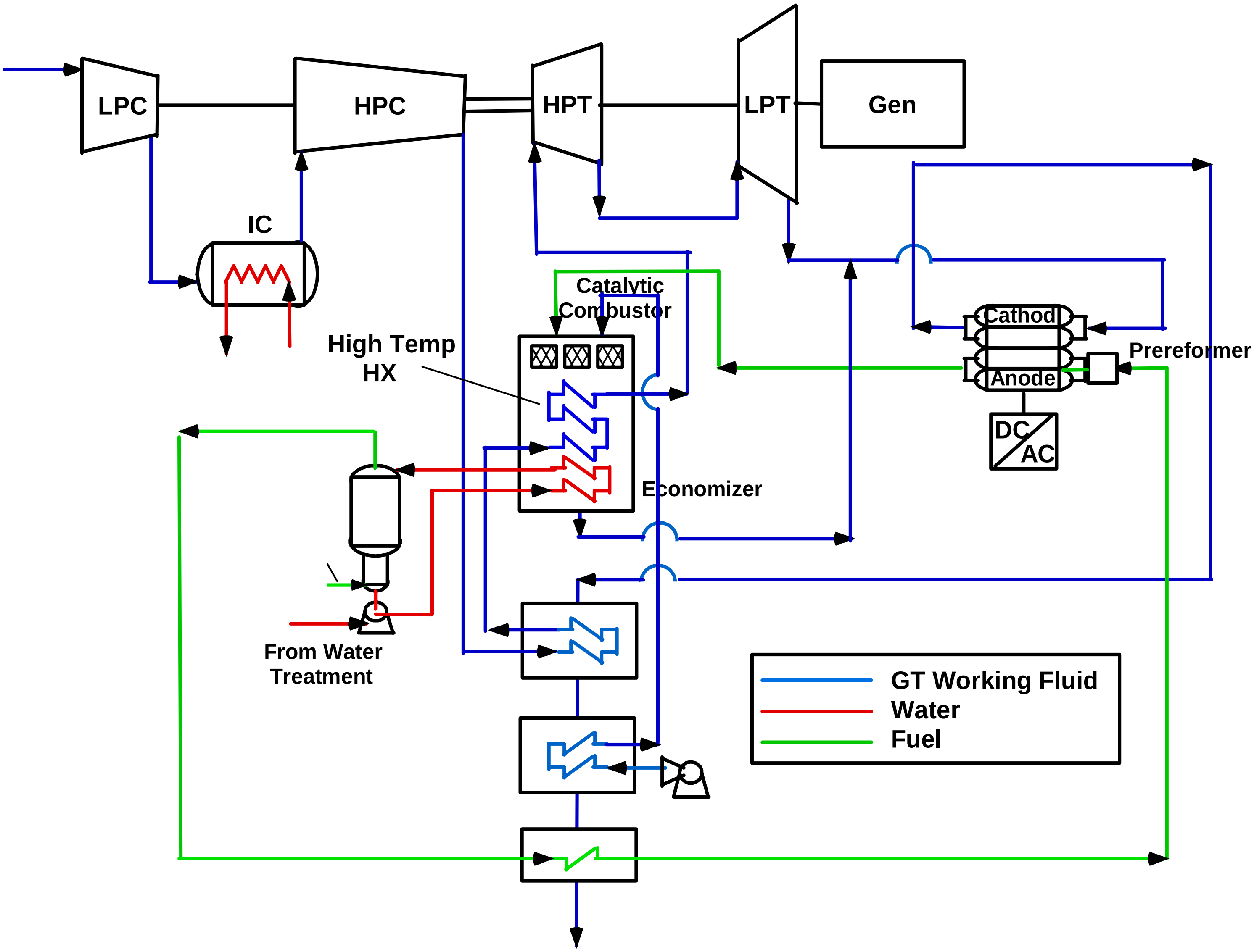

FIGURE 7: ATMOSPHERIC PRESSURE MCFC/INTERCOOLED GAS TURBINE HYBRID

High Pressure SOFC Integrated with O_2 Breathing HAT cycle

This case as depicted in Figure 8 is similar to the previously described HP SOFC integrated with the HAT cycle except that the HAT utilizes pure O_2 supplied by ion transport membrane (ITM) unit [Richards, 2001] instead of air. The exhaust gas consisting of water vapor and CO_2 is cooled by direct contact with circulating water in a dehumidifier after heat recovery, a portion of the CO_2 is purged from the cycle while the remainder is combined with the O_2 supplied by the ITM unit and recycled to the suction of the HAT (assisted by the induced draft fan) in order to moderate the combustion temperature within the combustor of the HAT engine. The CO_2 purged from the cycle may be compressed and to a pressure dictated by the ultimate disposal method chosen for sequestration. For this evaluation, a pressure of 60 bar was used in order to make a direct comparison with the advanced Rankine cycle case described next which produces the CO_2 at 60 bar. This cycle in addition to producing CO_2 also produces water on a net basis for export. The efficiency of the cycle is being developed.

The pressure ratio for the cycle and the gas turbine firing temperature were kept at the same values as those for the SOFC/HAT hybrid case. The gas turbine firing temperature sets the amount of CO_2 recycle.

It was determined also for this configuration that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric while if higher air to fuel ratios are to be utilized in the SOFC, then in order to meet the efficiency goal, the alternate approach consisting of installing a second SOFC between the HP and LP turbines is required. This alternate cycle configuration as pointed out earlier would increase the plant cost and complexity and was discarded from further consideration.

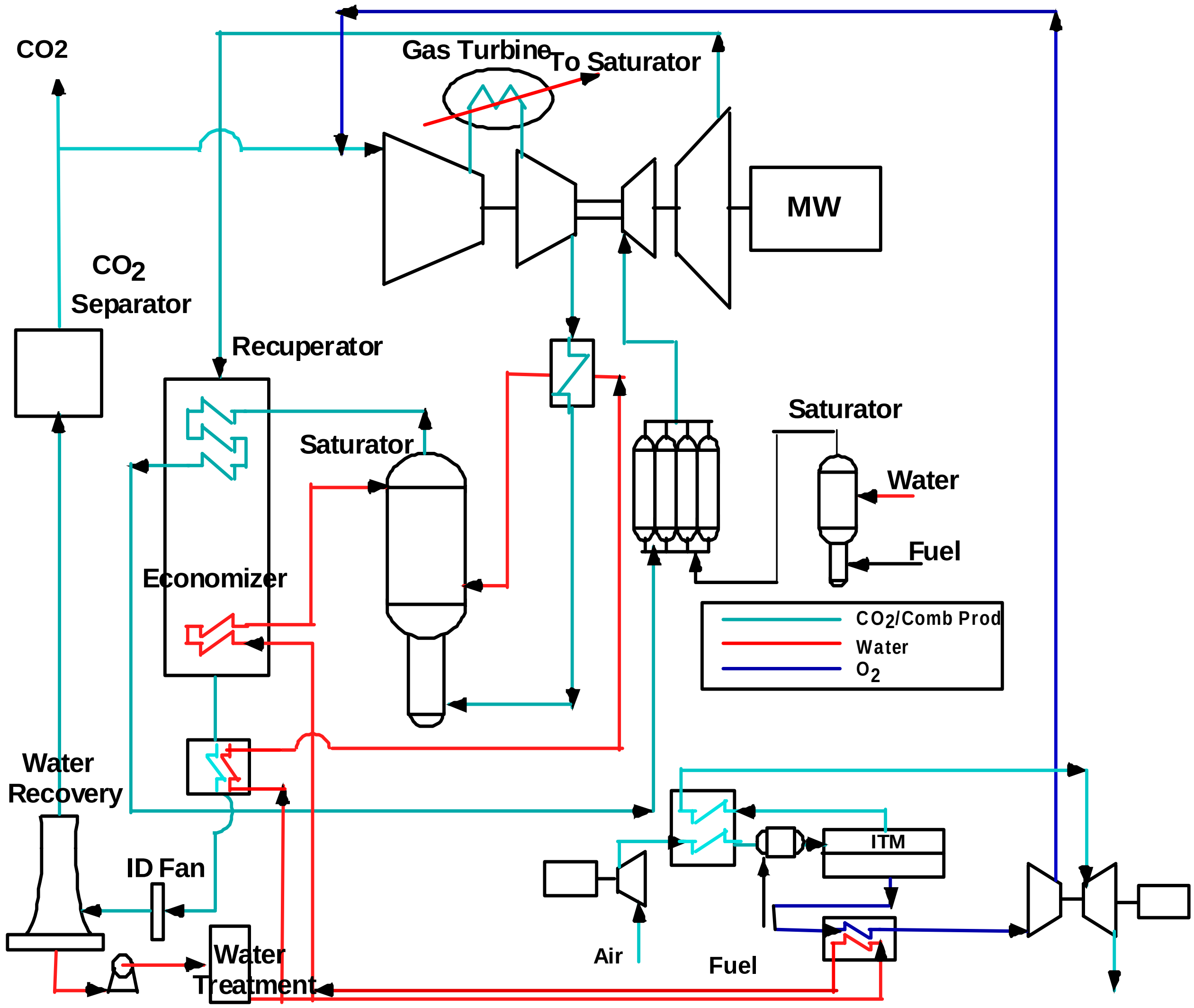

FIGURE 8: HIGH PRESSURE SOFC/O_2 BREATHING HAT HYBRID

Advanced Rankine Cycle Combusting H_2 with O_2

This cycle as depicted in Figure 9 utilizes a high temperature and high pressure reheat steam turbine operating with inlet conditions of 1760C and 222 bar to expand the steam produced by combustion of H_2 with stoichiometric amount of O_2 in rocket engine technology derived combustor [Anderson, 2001]. The H_2 is produced in a steam/methane membrane reformer [Lou, 2001] in which the H_2 chemically diffuses through a high temperature membrane as it is formed. Thus, the membrane reformer not only provides a separated pure H_2 product stream but also drives the reforming reaction to completion since one of the products of reaction (H_2) is continuously removed from the reaction mixture. The O_2 is produced in an ITM unit similar to the previous case. The steam turbine is similar to the turbine of a gas turbine because of the very high temperature of the working fluid. Both the HP and the reheat combustors utilize water injection to moderate the combustion temperature.

The CO_2 is recovered from the membrane reformer effluent for export at a pressure of 60 bar. The resulting efficiency of the cycle is 52% on a LHV basis.

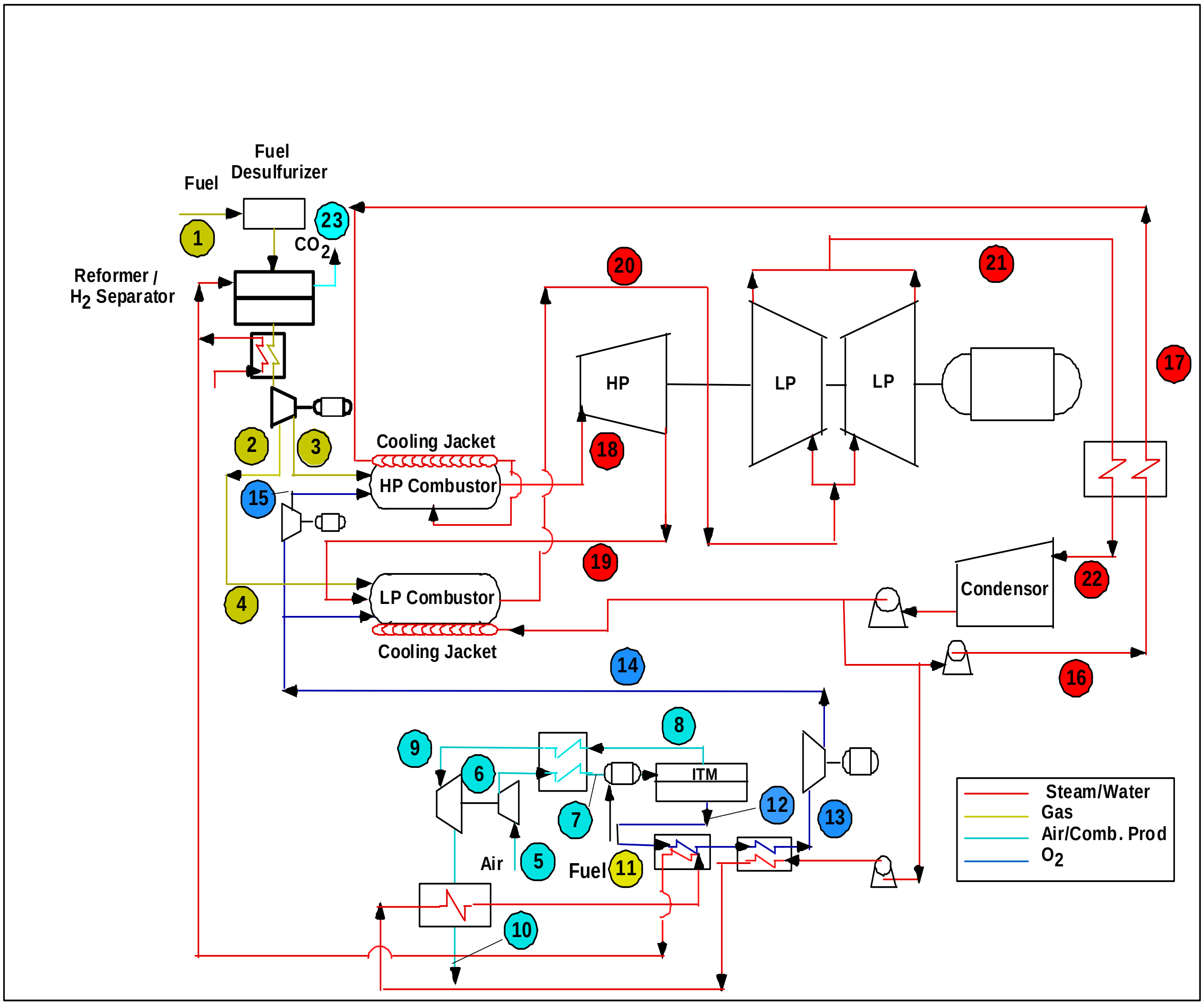

FIGURE 9: ADVANCED RANKINE CYCLE/COMBUSTING OF H_2 WITH O_2

CONCLUSIONS

CYCLE ANALYSIS

<u>HIGH PRESSURE SOFC INTEGRATED WITH HIGH PRESSURE RATIO INTERCOOLED GAS TURBINE</u>

It was determined that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric. If higher air to fuel ratio were used in the HP SOFC, then in order to meet the efficiency goal, an alternate approach consisting of installing a second SOFC between the HP and LP turbines would be required (a "reheat cycle"). This alternative configuration, however, did not significantly improve performance and would increase plant cost and complexity.

The optimum efficiency of the cycle occurred at an OPR greater than 50, while the gas turbine firing temperature was modest, <1200 C. As mentioned above, several configurations resulted in nearly equal performance, e.g., a non-intercooled gas turbine with an OPR of 20 had an efficiency only 0.3 points lower, well within computational error. When efficiency was a toss up, the intercooled gas turbine was chosen because of its higher power density (kW/air flow), a factor that would mitigate the system costs. This is especially true with the hybrid since the optimum cycle efficiency occurs when the only heat to the gas turbine is from the SOFC – the hot exhaust further heated by catalytic combustion of the remaining hydrocarbons in the exhaust. Since these temperatures seldom exceeded 1150 - 1200 C, power (kW/air flow) is somewhat limited.

<u>HIGH PRESSURE SOFC INTEGRATED WITH HAT</u>

It was determined also for this configuration that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric while if higher air to fuel ratios are to be utilized in the SOFC, then in order to meet the efficiency goal, the alternate approach consisting of installing a second SOFC between the HP and LP turbines is required. This alternate cycle configuration as pointed out earlier would increase the plant cost and complexity and was discarded from further consideration.

The optimum efficiency of the cycle occurred at an OPR of approximately 20, which is much lower than the previous case, while the gas turbine firing temperature remained at a modest value of <1200 C.

<u>ATMOSPHERIC PRESSURE MCFC INTEGRATED WITH INTERCOOLED GAS TURBINE</u>

It was found that in order to reach the 75% (LHV) efficiency target for this hybrid case, the fuel utilization had to be increased from the 85% value that was employed in the two SOFC hybrid cases to 90% fuel utilization resulting in a correspondingly lower heating value for the depleted fuel for the MCFC hybrid. The optimum OPR for the gas turbine from an efficiency standpoint for the proposed selected case was 25 while the gas turbine inlet temperature remained at a modest value of <1100C.

HIGH PRESSURE SOFC INTEGRATED WITH O_2 BREATHING HAT CYCLE

It was determined for this configuration that in order to reach the efficiency goal of 75% (LHV), the SOFC had to operate with a fuel to air ratio approaching stoichiometric while if higher air to fuel ratios are to be utilized in the SOFC, then in order to meet the efficiency goal, the alternate approach consisting of installing a second SOFC between the HP and LP turbines is required. This alternate cycle configuration as pointed out earlier would increase the plant cost and complexity and was discarded from further consideration.

ADVANCED RANKINE CYCLE COMBUSTING H_2 WITH O_2

The efficiency of the cycle is estimated at 52% on a LHV basis.

TECHNICAL INFORMATION REQUIREMENTS

A series of eight technologies were identified as requiring significantly more information than available in the literature:

1. The combustor for the Clean Energy Systems high temperature Rankine cycle
2. Details for the Foster Wheeler HIPPS cycle
3. Details for the Fast Transport Reactor Gasification System
4. Details for the GE EERC Hydro-gasifier
5. Performance estimates for advanced cryo air separation units
6. Details for the Ion Transport Membrane Oxygen separator
7. Details for the Ion Transport Membrane for Hydrogen separation
8. Details of the Fischer-Tropsch reactor

For each of these areas, requests were made for details on flow parameters such as temperature, pressure, constituents, and for auxiliary requirements for utilities and steam/water. Without these details, the analyses will proceed with our understanding of the system operation, or with alternative processes for which we have sufficient detail to develop suitable analytical models.

NON-TECHNICAL ISSUES AFFECTING INTEGRATION (TASK 3)

The California and western US energy crisis continued to heavily influence all forecasts for future commodity supply and demand which had compounded the difficulty in these tasks being conducted by Spencer Management Associates. Under partial auspices of this Task, an article was written for the February 2001 issue of Gas Turbine World that will document the causes of the failed CA deregulation and the implications upon future gas turbine design and performance characteristics (please see Appendix 1).

The California failure has been a hard $12 billion lesson to the utility shareholders, ratepayers and state taxpayers; however, it has strongly defined the operating characteristics needed in the next decade of generating capacity. It is undeniable that there will be a consolidation of the merchant plant players that will have three capabilities: generating capacity, natural gas resources and the ability for instantaneous commodity trading. There is a clear emergence of four highly valued operating characteristics for merchant plant generating assets: a) high variable output performance without significant efficiency penalties b) fuel type versatility, c) fuel use efficiency and d) ultra low environmental emissions. The current and future merchant plants built will acquire long term debt based upon the regional fit of the technology, the characteristics described above and the strength of the owner/operator's commodity trading ability. Commercial and industrial companies with demands for highly reliable power will gravitate to distributed generation with smaller gas turbines (and fuel cells in the future) since these companies now are more creditworthy than the IOUs and would therefore have a favorable ability to hedge the future price of their natural gas fuel. This prognosis was further validated on February 8, 2001 when Governor Davis expressed his support for legislation that would provide $20 million for 40 additional megawatts through the retrofitting of natural gas distributed generation owned by municipal water districts. More importantly, he supported the elimination of the standby charges for small renewable and other clean distributed generation.

There is an emerging upper bandwidth of future energy pricing from the recent CA 3, 5 and 10 year auctions. Preliminary reports are that the average bids of $69 a megawatt hour were received which were higher than the $55 officials had hoped for. The politicians have noted that these prices were still far lower than the $600 the state has sometimes had to pay on the open market. The CA rapid fired long term auction in response to the FERC Order of December 15, 2000 south 6 month, 3, 5 and 10 year bids from energy wholesalers. The details of these bids were initially sealed, but with time they were made public. This competitive bid information provides Vision 21 an excellent view of what the market would offer to solve a crisis for creditworthy customer like the CA Department of Water Resources (CDWR). Reliant Energy of Houston was the first bidder to reveal the substance of their bid in response to the narrowly scoped RFP.[1] By separating the cost of natural gas from the cost of converting that fuel into electricity, Reliant Energy also included in its proposals offers to provide electric generation

[1] Reliant Electric as reported in PRNewswire, "Submits Bids in California Electricity-Supply Auction;Company Also Offers More Flexible Solutions", January 24, 2001.

capacity at a cost as low as 1.6 cents per kilowatt-hour (KwH) for 10 years or 2 cents per KwH for five years, not including the price of natural gas to fuel its power plants. In order to offer this price, the California Department of Water Resources (DWR) would buy the natural gas and Reliant Energy would convert it into electricity. The lower the price at which DWR would be able to secure natural gas, the lower the total cost would be.

The company was only able to offer up to 500 MW of on peak power that largely conforms to the bid qualifications because those strict qualifications made it difficult for suppliers to manage fuel cost risks. The RFP's seven day evaluation period exposed Reliant to natural gas price fluctuations, it restricted bids from post new generation facilities coming on line after 2001 and it did not provide reasonable contingencies for unscheduled outages. "Our hands were tied in the auction on how much generation capacity we could offer because of the restrictive bid parameters in this process. We have offered more attractive and competitive alternatives in the additional proposals we submitted" said a Reliant spokesperson.

In relative terms, Reliant Energy contends that its alternative bids are at prices that are actually lower than prices charged by the investor-owned utilities (IOUs) prior to deregulation because the company is offering 2 cents or less per KwH, not including fuel costs. Prior to deregulation, fuel costs averaged less than 2.5 cents per KwH. If fuel costs were at these 1998 levels, the company's offer would result in total prices of energy less than 4.5 cents per KwH. This compares to IOUs' rates prior to deregulation, which were as high as 6.5 cents per KwH.

Reliant Energy said it is capable of increasing the amount of capacity it can make available under long-term contracts if the qualifications were more flexible. The company submitted five additional proposals that offer more capacity by addressing each restriction. In these bids, Reliant Energy makes it clear that it can offer up to 3,500 MW of supply if restrictions are lifted.

Calpine Corporation (NYSE: CPN) announced today the signing of a $4.6 billion contract to provide much needed electricity to the State of California. The 10-year, fixed-price contract with the California Department of Water Resources will begin later this year and will continue through 2011. In one of the largest power sales agreements in the history of the independent power industry, Calpine commits to sell up to 1,000 megawatts of clean, affordably priced electricity from its portfolio of new and existing energy centers. Initial deliveries under this contract start October 1, 2001 with 200 megawatts, and build to 1,000 megawatts by January 1, 2004. The electricity will be sold directly to the State's Department of Water Resources on a 24-hour, 7-day-a-week basis.

Therefore, this CA auction provides V21 the best 6 mo, 3, 5, 10 year barometer of energy prices in a constrained market; thus, it should be regarded as the upper end of the future bandwidth for credit worthy energy consumers in a gas/hydro dominated market. Once the details of the bids are released, it will be determined what the prevalent trends may be in the future

The EIA's 1999 forecasts for fuel and electricity prices will be utilized in this study for the lower bandwidth.

Spencer Management Associates, the participant of this study, believes that there is stronger evidence of a cyclical nature in the US power supply business and therefore subscribes to the views of Chris Seiple of Financial Times Energy.[2] Seiple contends that the winners in future merchant power plant generation will be those that are the low cost producers, technically superior, focused on profit capture rather "cost of electricity", has strong risk management capability, and are attuned to the cyclical nature of the business. Seiple documents the very strong correlation between the amount of surplus capacity in the regional markets and the price elasticity which also correlates to the regional interruptible demand uncertainty. Another indicator that is appearing, and based on some good data now from RDI, is that the US is going through another boom and bust cycle in terms of building generating capacity. The "dash for gas" new generating capacity will create a potential surplus of capacity in the 2004-2008 time frame, and retrofitting of the 1990s era installed capacity may be more prevalent than greenfielding new power plants in 2010-2020. This is not a positive indicator for V21 concepts, but we have to address this issue.

Spencer Management has prepared a subchapter on "The CA Deregulation Autopsy" (Appendix 1), and the "list of probably causes of death" now stands at 18. The $12B of debt accumulated by EIX and PG&E will cause the subject to be studied extensively over the years, but it is important for Vision 21 to note two things: a) the mistakes made in CA will be strenuously avoided in the ripple effect from CA, and b) there are other deregulation schemes (TX and PJM) that are being regarded as the superior model and which other states and countries may replicate.

The early stage of deregulation around the country has also brought us other indicators of future competitiveness of various technologies and fuels. Clearly there will be fairly well defined "regionalisms" of where fuel-type systems will be the most competitive based upon alternatives and transmission capacity.

One other thing that we know, and will be reported in the text, is that the shift to merchant plants brought an end to long term, natural gas supply contracts. Formerly, an IPP developer offset his long term energy purchase power contracts with a credit worthy utility with a long term gas supply contract (and some hedges) that would satisfy the lenders to the project. The current and future merchant plants will acquire long term debt based upon the regional fit of the technology, the characteristics described above and the strength of the owner/operator's three legged stool. Long term power purchase agreements and long term fuel supply contracts have become a relic of the past.

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[2] Chris Seiple, Director of RDI Consulting, FT Energy, "Assessment of Cyclical Trends in US Power Supply Business", CBI Merchant Plant Conference, January 18, 2001.

Spencer Management Associates continued to compile market and fuel information related to Tasks 3.3 and 3.5 of the Statement of Work. Data included in the compilation and analysis of data included the following reports:

1. The Energy Information Administration (EIA) released today a study entitled "Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard". This analysis responds to a request from the Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the U.S. House of Representatives Committee on Government Reform. This report describes the impacts of imposing caps on power sector emissions of nitrogen oxides, sulfur dioxide, mercury, and carbon dioxide with and without a renewable portfolio standard.
2. October 2001 NOx trading analysis
3. EPRI’s Western States Power Crisis: Imperatives and Opportunities
4. Montreux Energy Conference papers May 29-31, 2001
5. The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply, May 2001, Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 20585
6. Reliable, Affordable, and Environmentally Sound Energy for America’s Future Report of the National Energy Policy Development Group
7. 2001 SUMMER SPECIAL ASSESSMENT, Reliability of the Bulk Electricity Supply in North America North American Electric Reliability Council May 2001
8. U.S. Natural Gas Markets: Recent Trends and Prospects for the Future, May 2001,Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, DC 20585
9. The updated Emissions & Generation Resource Integrated Database (E-GRID) which is a comprehensive database of environmental attributes of electric power systems. E-GRID is based on available plant-specific data for all U.S. electricity generating plants that provide power and report data to the U.S. government. Data reported includes generation (in MWh), resource mix (for renewables and nonrenewables), emissions (in tons for NOx , SO2 , and CO2 ; and in pounds for mercury), emission rates (in both pounds per megawatt-hour [lbs/MWh] and pounds per million Btu [lbs/MMBtu] for NOx , SO2 , and CO2 ; and in both pounds per gigawatt-hour [lbs/GWh] and pounds per billion Btu [lbs/BBtu] for mercury), heat input (in MMBtu), and capacity (in MW).

Interviews are being arranged in the next quarter with major developers of DME and F-T fuels production including Mark Agee, President of Syntroleum, the alternative fuel specialist at the International Energy Agency, Rentech and other related DME and F-T experts.

FUTURE ACTIVITIES

Analyses of the configurations identified for the coal based cases will be completed as part of the Task 1.4 activities during the second year of the contract.

The ongoing draft report of approximately 250 pages will be expanded and refined during the next quarter to reflect the new fuels data, interviews conducted, industry reports and trends.

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APPENDIX 1

CALIFORNIA DEREGULATION AUTOPSY REPORT FOR GAS TURBINE WORLD

AN AUTOPSY OF CALIFORNIA'S EFFORT TO DEREGULATE THE ELECTRIC UTILITIES (1996-2001) - BY BYRON WASHOM, SPENCER MANAGEMENT ASSOCIATES

California was one of the first states to legislatively move to deregulate its traditional electric utility monopolies by opening the market to competition among independent power generators in order to give customers a choice of power providers and to drive down retail prices. In January 2001, regulators and politicians declared that the CA deregulation was flawed, had failed and was now dead. While many speculated what to do with the cadaver, what was known was the state's energy crisis had left its two largest investor owned utilities (IOUs), Southern California Edison and Pacific Gas and Electric Co., $12 billion in debt and unable to buy any more power on credit. The CA Legislature's $400 million emergency measure to stop the utilities' financial hemorrhaging was exhausted in just 12 days of brokering wholesale energy for the near bankrupt utilities. California's estimated $10 billion bond sale to finance future power purchases under the state's new emergency rescue package will be the largest municipal issue in history, but it does not address the accumulated debt of the utilities. The week of February 11th will witness major daily events by the courts, legislature, government agencies and creditors that will determine if the utilities seek bankruptcy protection.

During this 1996-2001 period, a number of other states and countries have enacted or contemplated variations to the CA model, but the unpredicted economic trauma on the world's sixth largest economy has rightfully caused serious reexamination of deregulation. While the long-term solutions are conservation, generation and price stabilization, it is becoming apparent that the most significant alteration will be the operating characteristics and sizes of gas turbine generation required in future restructured and deregulated markets.

It is not possible to pinpoint a single cause of death to California's deregulation policy and implementation, but there certainly can be a forensic-like assessment of the fatal flaws.

Supply of In-state Generation

1. Electricity consumption in California rose 18% last year alone, more than triple the national average[3], but it's been a decade since a power plant was built in California. The state has a cumbersome seven-year process for developing new capacity, and CA now imports approximately 25% of its electricity. Sen. Gordon

Smith of Oregon complained recently that his state is ``in jeopardy of becoming an energy farm to California."

2. California did not establish an effective transition from the regulated to the unregulated market since the energy pricing was tied to a successful recovery of the IOUs' stranded costs rather than the encouragement of significant competition.[4] Two independent audits indicated that the IOUs had paid their parent corporations $9.5B in dividends in the five years leading up to the electricity crisis[5] and that the stranded asset recovery was ahead of schedule. There was insufficient competition afterwards as witnessed by the fact that CA currently is at its 28th consecutive day of a Stage 3 Alert, i.e., supply reserves are less than 1.5% of forecasted demand.

3. California's aging transmission grid was designed and built under the generation-transmission-distribution monopoly model and thereby archaic for transmitting greater amounts of marketed electricity to areas with insufficient local generating capacity.

4. IPPs competitively bid for aging in-state generating assets, but some of these assets became unavailable during last year's "super summer peak periods" and this unusually cold, dry winter due to unscheduled maintenance, scheduled major overhaul or repowering.

Fuel Pricing and Availability

5. The IPP's "dash for gas" in new generating capacity, pipeline capacity constraints and an unseasonably cold winter has caused natural gas prices to quadruple in a year.

6. The financial insolvency of PG&E resulted in the CPUC approving a plan on January 31 to keep natural gas flowing to millions of PG&E customers by letting the natural gas suppliers draw directly on the revenues PG&E collects from monthly gas bills from its customers.

Policy Framework

7. California set up a highly restrictive power exchange system (CalPX) where most of the power used in the state was bought and sold on day-ahead trading. The IOUs were required to buy their power from CalPX, prohibited from hedging into future markets, and encouraged to sell off the majority of their generating assets. The CalPX has now ceased operations.

8. Taking the highest successful bid submitted by wholesalers set the CalPX price. Initially generators kept their bids low to ensure their plants were utilized while knowing they would receive the higher market-clearing price. When demand began to exceed supply, the wholesalers tested the elasticity of demand and found the opportunity for price spikes up to ten fold over the previous year.

9. There was an insufficient supply of contracted "spinning reserve"; therefore, the state's other pooled electricity market, the Independent System Operator (ISO), had to bear even higher prices when tight electricity supplies occurred through unscheduled outages or a shortage of generation capacity. This forced them to buy power on the hourly spot market to prevent blackouts. The largely out of state energy wholesalers have exacerbated the crisis by taking advantage of the tight supplies for their own profit.

10. Even though the *wholesale* rates were deregulated, CA instituted a *retail* rate freeze that blocked utilities from passing on higher wholesale costs to their customers. As a consequence, PG&E and SCE accumulated $12B of debt within a six month period due to the inability to bill customers for inflated wholesale prices.

11. The California-only price "soft cap" exacerbated the state's energy shortage because suppliers stepped up their sales to other Western states willing to pay above the CA price caps, leaving less energy for California.

12. The Federal Energy Regulatory Commission (FERC) declined to impose immediate wholesale price controls, but it did urge the state on Dec. 15, 2000 to sign long-term supply contracts instead of relying on the volatile short-term spot market to buy wholesale electricity.[6] President Bush extended by two weeks, until Feb. 7, directives put in place by the Clinton administration to force power suppliers to continue shipping electricity to California, but Bush made it clear he did so reluctantly and would not (and did not) issue further extensions.

Market Factors

13. Once the utilities started to default on their bonds, miss contract payments and threaten bankruptcy, out-of-state power suppliers resisted selling needed electricity to California.[7] Unless forced by the FERC, wholesalers had little incentive to sell power to CA and potentially become unsecured creditors in a bankruptcy. Some wholesalers have filed with the SEC that as much as 25% of their uncollected CA operating income is being held as an accounting reserve.

14. The IPPs had additional incentives to cut back electrical supply to CA during the month of January, 2001 since the value of the natural gas therm was greater than if it were converted into a MWH; thus they sold the natural gas commodity to a

credit worthy customer rather than produce and sell the MWH. Then once they created a shortfall in MWH supply by their production cutbacks, they were able to quickly reenter the electrical supply market and sell limited quantities of MWH at inflated prices with substantial profits. By agile trading, they were able to sell at the elevated peak of both commodities' markets.[8]

15. Standard & Poor's, Moody's and Fitch lowered the credit ratings on the IOUs, ending any continued and inexpensive debt funding.

16. A hot summer and a cold and dry winter reduced the hydroelectric supply.

17. An academic group released an "Energy Manifesto" which proclaimed that retail rates would need to rise 30-40% to inspire the conservation that would concurrently create market stability and rebuild the financial solvency of the utilities.

Environmental

18. There are strict environmental rules that make building plants in CA difficult. President Bush is considering letting the state roll back its air pollution controls for power plants.

19. On December 5, 2000, when operating reserves were forecasted to fall below seven percent, more than 11,000 megawatts of generation remained off line. The majority was categorized as forced outages including a substantial amount of power plant capacity shut down because of expired annual air emission credits. Governor Davis on February 8 used his emergency powers to order a streamlined, 21-day approval process for new power plants and easing emissions controls on older generating units that had exhausted their pollution credits. The Governor is also directing the California Air Resources Board (ARB) to establish a State Emissions Offset Bank to allow facilities to pay mitigation fees to compensate for increased operations. Mitigation fees will be used to maintain State and Federal air quality standards by cleaning up facilities and mobile sources that pollute the air, such as older power plants and diesel machinery. This ensures the state's ability to increase generation while maintaining California's commitment to air quality.

On January 25, 2001, Federal Reserve Chairman Alan Greenspan warned that if the CA energy crisis isn't resolved soon, it could cause a ripple effect throughout the U.S. economy that could undermine the nation's decade-long expansion. ``It's scarcely credible that you can have a major economic problem in California which does not feed to the rest of the 49 states," About a third of the states that have not yet opened their power markets to competition are slowing down the process or taking another look at deregulation. So far, twenty-four states and the District of Columbia, which comprise 60 percent of the U.S. population, have moved to deregulate their retail power markets. The PJM

(Pennsylvania / New Jersey / Maryland) and Texas deregulation models are now being hailed as the vanguards of deregulation that avoid the weaknesses legislated in CA.

The California failure has been a hard $12 billion lesson to the utility shareholders, ratepayers and state taxpayers; however, it has strongly defined the operating characteristics needed in the next decade of generating capacity. It is undeniable that there will be a consolidation of the merchant plant players that will have three capabilities: generating capacity, natural gas resources and the ability for instantaneous commodity trading. There is a clear emergence of four highly valued operating characteristics for merchant plant generating assets: a) high variable output performance without significant efficiency penalties b) fuel type versatility, c) fuel use efficiency and d) ultra low environmental emissions. The current and future merchant plants built will acquire long term debt based upon the regional fit of the technology, the characteristics described above and the strength of the owner/operator's commodity trading ability. Commercial and industrial companies with demands for highly reliable power will gravitate to distributed generation with smaller gas turbines (and fuel cells in the future) since these companies now are more creditworthy than the IOUs and would therefore have a favorable ability to hedge the future price of their natural gas fuel. This prognosis was further validated on February 8 when Governor Davis expressed his support for legislation that would provide $20 million for 40 additional megawatts through the retrofitting of natural gas distributed generation owned by municipal water districts. More importantly, he supported the elimination of the standby charges for small renewable and other clean distributed generation.

The California legislative has authorized $10B for the state entering into contracts for as long as 10 years to buy wholesale electricity for about one third of the state's demand at a stable price and sell it to the IOUs. Future legislative efforts contemplate having the state issue revenue bonds to cover the utilities' debts and make their customers pay the money back over a decade through recently approved rate increases of 9 percent for residential customers and 7 – 15% for businesses. The *quid pro quo* may be the state's taking ownership of the two utilities' 26,000-mile mile network of high voltage transmission lines carrying power to about 24 million of the state's 34 million residents. Regardless of any actions taken by federal or state officials, California and the western U.S. will remain in a perilous energy and economic crisis at least through the summer of 2001, and the reappraisal of restructuring policies will be as intense as the drive to optimize the new individual and mix of generating technologies needed to serve the future markets.

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